Oil and Gas News Briefs
Compiled by Larry Persily
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[BP reduces oil exploration team from peak of 700 to under 100]

(Reuters; Jan. 24) - Nothing escapes the changes now sweeping through BP, not even the exploration team that for more than a century powered its profits by discovering billions of barrels of oil. Its geologists, engineers, and scientists have been cut to less than 100 from a peak of more than 700 a few years ago, company sources said, part of a climate change-driven overhaul triggered last year by CEO Bernard Looney.

Hundreds have left the oil exploration team in recent months, either transferred to help develop new low-carbon activities or laid off, current and former employees said. The exodus is the starkest sign yet of the company's rapid shift away from oil and gas, which will nevertheless be its main source of cash to finance a switch to renewables for at least the next decade. BP declined to comment on the staffing changes.

Looney made his intent clear by lowering BP's production targets and becoming the first oil-major CEO to promote this as positive for investors seeking a long-term switch to a lower-carbon economy. BP is cutting 10,000 jobs, about 15%, under the restructuring, the most aggressive among Europe's oil giants. The oil engineer, who previously led the oil and gas exploration and production division, Looney aims to cut output by 1 million barrels a day, or 40%, over the decade while growing renewable-energy output 20 fold.

For the smaller exploration team, the focus has narrowed to searching for new oil and gas resources near existing fields to offset production declines and minimize spending. And a team of geologists and data crunchers will apply analytics that used to study and map rock structures in search of fossil fuels to now develop low-carbon technologies such as carbon capture, usage, and storage and geothermal energy, sources said.

[Keystone decision raises doubts of U.S. as customer for Canadian oil]

(Calgary Herald columnist; Jan. 21) - On his first day as president, Joe Biden pulled the pin on Keystone XL. The political fallout reverberated on both sides of the border, as pipeline opponents set their sights on other infrastructure that transports Canadian oil into the United States, such as an Enbridge project to replace a pipeline called Line 3 from Alberta to a connection point in northern Wisconsin.

TC Energy didn't say so officially, but its Keystone XL will likely end up in the graveyard of unsuccessful pipeline proposals, joining Energy East from Alberta to Canada's East

Coast and Northern Gateway from Alberta to the West Coast. But the broader question is: Will the decision have ramifications for other pipelines to move Canadian oil and gas to the country's largest customer? "It does set a precedent because this has not been done before … something of this scale and this kind of ping-pong approval process and challenge," Canadian Energy Pipeline Association CEO Chris Bloomer said.

"The real issue Canada has to think about is just how durable is our long-standing, trustworthy economic partnership with the United States?" said Hal Kvisle, the former CEO of TransCanada (now TC Energy) when Keystone XL was first proposed in 2008. With the development sidelined, attention turns to other pipelines, including Enbridge's Line 3 project and its existing Line 5 pipeline, which has drawn opposition in Michigan. While Keystone XL was a proposed pipeline, the other projects are operating lines. Any changes to those replacement projects would affect consumers, not just producers.

Biden's stop to Keystone XL puts Trudeau in a tough spot

(Bloomberg; Jan. 21) - President Joe Biden's cancellation of the Keystone XL project has put Canadian Prime Minister Justin Trudeau in a no-win situation. He has no good options to retaliate for the loss of the Alberta-to-U.S. pipeline. But a failure to fight back could fracture the unity of his own country. Trudeau immediately came under pressure from Alberta Premier Jason Kenney, who called on the prime minister to consider trade sanctions against the U.S. It's unlikely Trudeau is willing to go that far.

The confrontation scrambles Trudeau's plans for a reset in Canada's relationship with the U.S. — by far its most important ally — after four years of bruising trade battles with Donald Trump. In Western Canada, a failure to push back on Biden will only sow greater mistrust over Trudeau's handling of the nation's oil riches. Keystone XL is a charged political symbol and economically vital project in Canada's west, worth billions of dollars a year in oil revenue. Building it would have opened the way for new energy development in Alberta and helped the region sell its heavy crude at higher prices.

In his winning 2015 campaign, Trudeau argued that stronger climate policy would help win approval for Keystone. It hasn't worked out that way, and Biden's move is likely to fuel further anger against the federal government in the west. "This is a gut-punch for the Canadian and Alberta economies. Sadly, it is an insult directed at the United States' most important ally and trading partner on day one of a new administration," Kenney said at a news conference Jan. 20, the day of Biden's announcement.

Pipelines would help oil sands producers earn more for their crude

(The Wall Street Journal; Jan. 22) - President Joe Biden's revocation of a permit for the Keystone XL pipeline is raising pressure on Canada's energy industry to seek new markets for oil and gas, its top export. Biden effectively shut down a 12-year, cross-border project that would have carried 830,000 barrels a day from Alberta to Nebraska and eventually to refiners on the Gulf Coast. Canada, the world's No. 4 oil producer, is left with fewer options to get its dense crude from landlocked oil sands to U.S. refiners.

Biden's decision won't immediately hurt Canada's oil industry because production and demand have fallen during the COVID-19 pandemic. In recent years, producers have increased the amount of crude transported to the U.S. by rail, traders said, reducing the need for Keystone XL. But the likely demise of the project has underscored how reliant Canada remains on the U.S., where refiners buy 98% of Canada's oil exports.

Canada's energy industry is pushing for more access to growing markets in China and India, pinning hopes on the completion of a pipeline next year that would extend from Alberta to an export terminal on the Pacific Coast. Because Canadian producers have such limited and costly options for getting their oil to buyers, it trades at a discount. The Western Canadian Select grade of dense oil sands crude traded at $39.30 on Jan. 21, $13.70 below the West Texas Intermediate benchmark, according to S&P Global Platts.

U.S. refineries are not clamoring for Keystone XL, because the additional capacity to market would have eased the logistical bottleneck that makes lower-priced Canadian crude one of the most profitable varieties for U.S. refiners, traders and analysts said.

Even without Keystone XL, Canada will have other pipelines to U.S.

(Reuters; Jan. 22) – The Keystone XL pipeline may be dead, but the U.S. is still poised to pull in record imports of Canadian oil in coming years through other pipelines that are in the midst of expanding. President Joe Biden canceled Keystone XL's permit on his first day in office, dealing a death blow to a long-gestating project that would have carried 830,000 barrels per day of heavy oil sands crude from Alberta to Nebraska.

Traders and analysts, however, said U.S.-Canada pipelines will have more than enough capacity to handle increasing volumes of crude out of Canada, the primary foreign supplier of oil to the United States. Currently, Canada exports about 3.8 million barrels per day to the United States, according to U.S. Energy Department data. Analysts expect that to rise to between 4.2 million and 4.4 million over the next few years. Pipeline expansions in progress will add more than 950,000 barrels per day of export capacity for Canadian producers before 2025, according to Rystad Energy.

Enbridge's Line 3 replacement project is in the process of doubling its capacity, allowing it to deliver about 760,000 barrels per day from Alberta to a Wisconsin connection point by the end of this year. The Canadian government is expanding the state-owned Trans Mountain line by 590,000 to 890,000 barrels per day. That line ends near Vancouver, where tankers could load up for the U.S. Meanwhile, TC Energy received U.S. approval last year to expand its existing Keystone line located far from the proposed Keystone XL, which would add 170,000 barrels per day into the U.S. Midwest and Gulf Coast.

Alberta might have avoided the pipeline problem if it had shared

(Bloomberg commentary; Jan. 24) - President Joe Biden's decision to revoke the permit for the Keystone XL oil pipeline wasn't a surprise, but it dismayed Canadian provincial and national leaders nonetheless. It thrusts squarely back on their shoulders a problem that has dogged the province of Alberta's oil and gas industries for decades: How to get what they produce to international markets. Alberta dominates Canada's oil production and if it can't develop its own export system, those riches risk being left in the ground.

The challenges to achieving such a thing are both geographical and political. Alberta is landlocked. In that sense it's little different to Azerbaijan or Kazakhstan in Central Asia, or Uganda in Central Africa. While the territories between the oil sands deposits and the open seas may not all be foreign countries, what with Canada's federal structure, they might as well be. And Alberta's neighbors don't share its enthusiasm for hydrocarbons.

Canada's West Coast would be the most obvious jumping off point for oil exports to Asia. But stiff opposition in British Columbia has prevented Alberta's producers from taking full advantage of that opportunity. And, sadly, Alberta's own politicians have refused to give other provinces much incentive to help out. Back in 2012, Alberta's energy minister said the province wouldn't share its oil and gas royalties with British Columbia to facilitate transit accords. Giving British Columbia a financial incentive to host export pipelines was one tool Alberta never seemed willing to take out of the box. Alberta has itself to blame. If it had been more willing to share the wealth a decade ago, when people were concerned about oil running out, they might have got their pipelines.

Canada, U.S. at odds over pipeline under Great Lakes

(The Wall Street Journal; Jan. 19) - Canadian and U.S. officials are at odds over the fate of a pipeline underneath the Great Lakes, exacerbating disagreements over energy policy between the two nations. Citing environmental concerns, Michigan officials have told Enbridge to close its Line 5 pipeline, which carries more than half a million barrels of oil and natural gas liquids each day from Superior, Wisconsin, to Sarnia, Ontario.

Canadian officials say closing the line would choke off more than half of the supply used to make gasoline, jet fuel, and heating oil for the most populous parts of the country. The 645-mile pipeline, which is part of Enbridge's mainline system that conveys Alberta's oil and gas liquids, feeds refineries in Michigan, Ohio, Pennsylvania, Ontario, and Quebec. Line 5 opponents say a spill would be catastrophic for the Great Lakes. Enbridge said the section of the 67-year-old line that runs beneath the Straits of Mackinac has never leaked, and the company will further protect the lakes by encasing the pipes in a tunnel.

Michigan Gov. Gretchen Whitmer said in November she was revoking a permit allowing the pipeline to run between Lake Michigan and Lake Huron. Michigan's government cited "the unreasonable risk" the line poses to the Great Lakes. She gave the company until May 12 to shut the pipeline. Enbridge sent a letter to Whitmer on Jan. 12 saying that only a court or federal order could shut down the pipeline. Enbridge has filed suit in federal court to stop the closure. Michigan is suing Enbridge in the same court to affirm its shutdown order. No date has been set for proceedings in either case.

Explorers see low-cost oil prospects offshore South America

(The New York Times; Jan. 20) - The Atlantic waters off Guyana have become one of the world's hottest oil-drilling zones. Now, international oil executives are looking at neighboring Suriname. ExxonMobil, Shell, Total, Apache, and several other companies are gearing up operations off Suriname's coast. They hope that the South American country of 600,000 residents — which recently emerged from decades of authoritarian and corrupt governments — will be the next great oil source.

But the world has more than enough oil, and prices for petroleum products are relatively low. In addition, investor interest in oil companies is waning as concerns about climate change give momentum to electric vehicles and renewable energy. Those concerns are not hurting interest in Suriname, where companies say they can make money at prices as low as $30 to $40 a barrel because of lower costs. That is below break-even in many places, including some U.S. shale fields where costs usually reach near $50 a barrel.

One reason it is easier to make money is that Suriname demands a smaller cut from oil companies than several other Latin American countries, including Brazil, Bolivia, and Mexico. Suriname wants to attract investment and jump-start a troubled economy and fix its ailing finances. The 30-year production-sharing agreements that Suriname is offering oil companies are also about five to 10 years longer than those offered by other Latin American nations, giving companies more time to invest, discover, and produce.

"The world is going to be using less oil over time. The winners in the race to share what remains of the oil pie will be those who can produce at low cost," said David Goldwyn, a top State Department energy diplomat in the Obama administration. In neighboring Guyana, companies have found more than 10 billion barrels of probable reserves of oil and gas offshore, according to IHS Markit. Production began in 2019 and is ramping up quickly. Suriname has at least 3 billion to 4 billion barrels, energy experts said.

U.S. drillers have years of stockpiled federal permits

(Reuters; Jan. 21) - President Joe Biden's promised ban on new oil and gas drilling on federal lands would take years to shut off top shale drillers because they already have stockpiled permits, according to interviews with executives. But smaller independent drillers without the resources of big corporations are more worried about Biden's vow to toughen regulations and stop issuing permits on federal lands, part of his sweeping plan to combat climate change and bring the economy to net-zero emissions by 2050.

Federal lands are the source of about 10% of U.S. oil and gas supply. Biden's pledge would reverse former President Donald Trump's efforts to maximize drilling and mining on federal property. In an order dated Jan. 20, the Biden administration suspended oil and gas leasing and permitting on federal lands for 60 days while it reviews the legal and policy implications of the mineral leasing program. But a freeze or ban will not end production in those areas overnight.

The seven companies that control half the federal supply onshore in the Lower 48 states have leases and permits in hand that could last years. David Hager, executive chairman of Devon Energy, the biggest oil producer on onshore federal land in the Lower 48, said the company's federal lands permits would last at least four years. Other top producers include EOG Resources, which has said it has at least four years of federal permits. Occidental said last year it had well over 200 federal drilling permits in hand and had requested another roughly 200 permits on New Mexico acreage.

Japan’s oil imports lowest in 50 years; LNG lowest since 2010

(Reuters; Jan. 21) - Japan’s oil imports fell to the lowest in more than 50 years last year as the pandemic hit economic activity and accelerated a long-term decline, while other energy purchases fell to decade lows, Reuters’ calculations showed. Liquefied natural gas imports also declined, dropping to the lowest since before the 2011 Fukushima nuclear disaster sent purchases by the world’s biggest LNG buyer soaring as reactors closed down, the preliminary data released Jan. 21 by the finance ministry showed.

Imports of thermal coal also dropped in 2020, falling for a third year as more renewable-energy projects were completed and some nuclear plants remained online, despite the shutdown of some operable units for regulatory upgrades. Crude imports into the world’s fourth-biggest importer of oil dropped 16% to 2.5 million barrels a day, the lowest since at least the late 1960s, according to the country’s trade ministry.

Japan’s imports of LNG came to 74.4 million tonnes in 2020, the lowest since 2010, the year before the nuclear disaster drove purchases to records amounts. Japan may lose its title as the biggest LNG this year as China’s purchases are fast catching up with the world’s biggest energy importer taking in a record 67.4 million tonnes of LNG in 2020.

Japan’s Sumitomo Corp. will stop investing in new oil projects

(Reuters; Jan. 24) - Japanese trading house Sumitomo Corp. will stop investing in new oil development projects as it shifts away from fossil fuels businesses amid a global push to cut greenhouse gas emissions, the Nikkei business daily reported Jan. 24. The move comes as global miners and Japanese trading companies cut their exposure to coal operations, including mining and power generation to trim harmful carbon dioxide emissions and to slow climate change.

Major Japanese trading houses have said they would stop investing in new projects to develop thermal coal mines or build coal-fired power stations, but this would be the first time that a Japanese trading firm decided not to invest in new oil projects, the Nikkei said. Sumitomo will no longer participate in auctions for new oil projects, though it will continue current projects, the paper said, without citing sources. In natural resources and energy, Sumitomo will focus on renewable energy such as offshore wind farms and base metals, including copper and nickel used in electric vehicles.

Biden moratorium on new leases faces opposition in Western states

(The Associated Press; Jan. 22) - President Joe Biden’s 60-day moratorium on new oil and gas leases and drilling permits is prompting widespread concerns in New Mexico, where spending on education and other public programs hinges on the industry. Top Republicans in the state as well as leaders in communities bordering the Permian Basin — one of the most productive oil regions in the U.S. — say any moves to make permanent the suspension would be economically devastating for the state.

Half of New Mexico's production happens on federal land and amounts to hundreds of millions of dollars in royalties each year. Congressional members from other Western states have raised concerns, saying the ripple effects of the moratorium will hurt businesses already struggling because of the pandemic. In Utah, the state's delegation asked for Biden to reconsider what they called an arbitrary decision.

Industry groups said the order effectively brings all regulatory activity to a halt from routine requests to rights of way for new pipelines designed to gather more gas as part of efforts to reduce venting and flaring — practices that Democrats have targeted in their fight against climate change. “It really has the opposite intent,” said Robert McEntyre, spokesman for the New Mexico Oil and Gas Association. “It means some natural gas is not going to be captured, and that’s not what operators want to do.”

[Asian spot LNG prices decline 70% from record high]

(Reuters; Jan. 22) - Asian spot liquefied natural gas prices fell this week as traders started to book cargoes for a warmer season, after a period of peak heating demand sent prices rocketing. The average LNG price for March delivery into northeast Asia was estimated at around $8.90 per million Btu, at the lower range of the $8 to $14 estimated the previous week, traders said.

Last week traders estimated cargoes for February at $29, after a record high of $32.50 on Jan. 13, according to the Japan-Korea-Marker, assessed by S&P Global Platts and used as a reference for markets in Asia. Individual companies paid nearly $40 during peak demand, according to consulting firms Energy Aspects and Timera Energy. Now Timera sees April prices at less than $7. "Market participants have always priced in a steep backwardation into the March period, due to expected warmer spring weather and lower subsequent demand," said Des Wong, head of EMEA LNG pricing for Platts.

[Baker Hughes expects up to 4 LNG projects may go ahead in 2021]

(Bloomberg; Jan. 21) - Baker Hughes expects as many as four LNG projects worldwide to move to final investment decisions this year amid a global revival of the fuel after last year's pandemic-induced collapse. The world's second-biggest oil services and equipment provider managed to weather history's worst oil crash thanks to its other business supplying LNG gear. The unit that houses its LNG work was the only one of its four units that boosted fourth-quarter sales from a year ago, the company said.

"By 2030, we still need to have capacity of approximately 650 million to 700 million tonnes of LNG in place," CEO Lorenzo Simonelli told analysts and investors Jan. 21 on a conference call. That would be about 200 million tonnes above global liquefaction capacity at the end of 2020. "You're looking at 50 million to 100 million tonnes FID'ing over the course of the next three to four years," Simonelli said.

The LNG industry took a gut punch in 2020 when more than 100 U.S. cargoes of the fuel were canceled as the coronavirus pandemic sent global demand and prices plunging. Only one project reached a final investment decision last year. The demand picture changed during the winter when frigid weather in Europe and North Asia sent spot prices soaring, raising the prospect of revived commercial talks with LNG developers around the globe.

[Woodside sees hope for new LNG deals from China]

(Sydney Morning Herald; Jan. 21) - Woodside CEO Peter Coleman said momentum is returning for plans to green-light the A$16 billion Scarborough offshore gas field project in Western Australia as Chinese buyers resume talks, commodity prices recover and rival projects are shelved or abandoned. After the COVID-driven oil and gas crash forced Woodside and joint-venture partner BHP to delay giving the go-ahead to the Scarborough project, a freezing Asian cold snap helped drive a stunning rally in prices for liquefied natural gas this month — prompting producers to increase their forecasts.

Coleman said Jan. 21 that Woodside was seeing "a lot of positive signs" that LNG demand was strengthening across Asia and globally. "Chinese buyers are now coming back into the market, they've approached us again recently to reengage on negotiations." However, Chinese companies that were in talks with Woodside to potentially acquire stakes in Scarborough walked away last year amid worsening diplomatic tensions between the two countries and have not returned to the table.

Woodside reported this week that Germany's Uniper agreed to double the amount of LNG it would buy from Scarborough, now locking in 40% of Woodside's expected share of the gas. But the company needs more buyers ahead of a final investment decision targeted for the second half of the year. Tom Allen, an energy and utilities analyst with UBS, said Woodside's expanded deal with Uniper "increases our confidence that Woodside can achieve a final investment decision for Scarborough by the end of 2021."

Russia plans earliest-ever LNG shipment through Northern Sea Route

(Bloomberg; Jan. 18) - Russia is preparing to make the earliest-ever shipment of liquefied natural gas to Asia, taking advantage of thinning ice in the Arctic Ocean and paving the way for a record-long navigation season this year. The cargo from Novatek's Yamal LNG facility in early May will beat last year's record for the start of eastbound voyages through the Northern Sea Route by almost two weeks if the plan works out, according to people familiar with the situation. It will travel with an icebreaker escort.

The Northern Sea Route, stretching more than 3,000 nautical miles between the Barents Sea and the Bering Strait, is the shortest passage between Europe and Asia. Yet its eastern part is usually closed to navigation for several months at the start of the year due to thick ice, limiting shipping potential. Its increased use underscores how quickly the pace of climate change is accelerating in the Earth's northernmost regions. The exact timing of this spring's first LNG shipment will depend on the thickness of the ice and weather conditions, said the officials, who asked not to be identified.

Russia expects the passage to rival the Suez Canal as Arctic ice thins out. Novatek sent an eastbound LNG cargo through the route with icebreaker support in late May 2020 — the earliest start to the navigation season in the area so far. Shipments continued to Asia through January, a record-long navigation season in the eastern Arctic. Earlier this month, Novatek sent two LNG ice-class tankers to China through the NSR. The vessels don't need icebreaker support, as the conditions in the eastern Arctic were mild.

Bank of America analyst expects hydrogen to play major energy role

(CNBC; Jan. 22) - Hydrogen is set to play a major role in the global energy markets over the coming decades, supplanting a large chunk of oil demand, according to Bank of America's head of global thematic research. Haim Israel said that while oil and gas would still be needed going forward, it was nearing a peak in demand. "We think it's peaking this decade, it's soon — way sooner than what everybody thinks," he said.

Israel listed several factors that would affect oil and gas going forward, including cheaper renewable energy, regulation, and the electrification of cars. "We believe that hydrogen is going to take 25% of all oil demand by 2050," he said, adding that oil was "facing headwinds left and right. Yes, we'll still need it. Yes, it's still going to be around, but the market share of oil is going to plummet."

Governments and companies worldwide have set goals to reduce their environmental footprint and move away from fossil fuels. The U.K. and European Union are targeting net-zero greenhouse gas emissions by 2050. If those goals are to be met, the world's energy mix will need to see a shift to renewable and low-carbon sources, a mammoth undertaking. "We … strongly believe that the 'big oils' need to think in different ways," Israel said. "They need to think about not 'big oil' anymore but 'big energy' from here onwards, to go much more into renewable sources, to diversify their sources."

Norwegian company will expand into green hydrogen

(Reuters; Jan. 21) - Norway's Nel, a maker of zero-emission hydrogen technology, will expand in 2021 to make its products more cost competitive, leading to a loss for the year, it said Jan. 21. Nel makes electrolyzers used to make so-called green hydrogen from water rather than fossil fuels, and also hydrogen-fueling equipment. Hydrogen, currently mainly used in oil refining and to produce ammonia for fertilizers, is lauded as a potential green fuel as it does not produce greenhouse gas emissions when it burns.

Nel's goal is to enable customers to produce green hydrogen at $1.50 per kilo in 2025, a cost where it can outcompete fossil alternatives, down from between $2.50 and $4.50 per kilo in 2019, it said in a strategy update. "Achieving this would allow green hydrogen to start to reach fossil parity, representing one of the most significant achievements for zero-emission solutions and a carbon-neutral planet," CEO Jon Andre Loekke said.

Green hydrogen uses electrolysis to split water into hydrogen and oxygen, an expensive method compared to extracting hydrogen from natural gas or coal. Finding a way to make this cheaply, or under $1.50 per kilo, is often described as the holy grail of green-energy transition. Nel is building a fully automated manufacturing facility for alkaline hydrolyzers in southern Norway and aims to expand the production capacity to beyond 2 gigawatts annually from the current nameplate capacity of about 360 megawatts.

[Utility plans to turn shuttered German coal plant into hydrogen hub]

(Bloomberg; Jan. 22) - Vattenfall plans to turn the site of its recently shuttered Moorburg coal power plant in northern Germany into a hub for turning wind and solar power into hydrogen. The Swedish state-owned utility is riding the growing enthusiasm for hydrogen, with many countries seeing the clean fuel as key to a low-carbon economy. Governments are planning generous subsidies to support the fledgling technology, with the European Union aiming to direct as much as 470 billion euros ($570 billion) of investment toward hydrogen infrastructure in the coming decades.

Vattenfall signed a letter of intent with Mitsubishi Heavy Industries, Shell, and local utility Warme Hamburg to see how the former coal plant could be transformed to produce hydrogen by 2025, it said in a statement. The plans include building a 100-megawatt electrolyzer to use renewable power to make what’s essentially a fossil-free fuel. The existing infrastructure of the 1,600-megawatt plant in Hamburg ensures there are enough power grid connections to accommodate large-scale hydrogen production.

The partners intend to submit their first outline of the project during the first quarter of this year as a part of an application for EU funding. Vattenfall halted the Moorburg coal plant at the end of last year after less than five years of operation as part of Germany’s program to phase out the use of the dirtiest fossil fuel for power generation. Warme Hamburg previously operated a gas-fired power station at the site.