Oil and Gas News Briefs
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Rising oil prices may turn consumers away from the fuel

(Reuters column; June 30) - Oil prices have risen above the long-term average, once adjusted for inflation, and are likely to encounter increasing resistance from consumers if they continue to climb. Front-month Brent futures are trading around $75 per barrel compared with an inflation-adjusted median of just over $70 since the start of the century. Investment bank Goldman Sachs forecasts prices will hit $80 this summer as the use of coronavirus vaccines allows more businesses to open and travel to resume.

But if prices continue rising to $80 and more, the increase is likely to draw more responses from policymakers, businesses and motorists in the major consuming countries. Somewhere between $75 and $85, oil prices will start to become politically sensitive and have an impact on consumer behavior and petroleum use. In particular, high prices will encourage an intensified focus on reducing consumption of petroleum-based fuels and accelerating the switch to alternatives such as electric vehicles.

Climate campaigners and promoters of electric vehicles may welcome a temporary price spike, since it would strengthen their case for an accelerated transition to zero-emission vehicles. For OPEC+, U.S. shale producers and the rest of the oil industry, however, significantly higher prices in the short term are likely to lead to an accelerated loss of demand by the second half of the decade. In thinking about their strategy, oil producers must weigh up short-term revenue gains from a spike in prices against long-term revenue losses from an accelerated reduction in oil consumption.

Russia has capacity to boost oil production back to near record

(Bloomberg; June 29) - Russia will be able to keep pace with any easing of OPEC+ production cuts in both the short and medium term, according to analysts including Bank of America and Fitch Ratings. As the cartel discusses whether to boost output in August, there has been renewed speculation about whether record production cuts could have permanently damaged Russian oil fields. While some old and inefficient wells have been shut for good in the past year, the country has largely preserved its pre-pandemic capacity, according to a Bloomberg survey of six analysts.

Russia could boost output by 700,000 barrels a day within six to 12 months, according to the average analyst estimate. That could return the country to just under the post-Soviet production record of 11.25 million barrels a day reached in 2019. “The massive freeze of production wells did not result in a significant reduction of output capacity, which many feared would be the case," said Dmitry Marinchenko, a director at Fitch.

At the OPEC+ meeting July 1, Moscow may try to persuade the group to boost output more quickly. "Russian producers have repeatedly proven that they can add back idle production on very short notice," said Ron Smith, senior oil and gas analyst at BCS Global Markets. Russia had to idle or shut an unprecedented number of wells within a couple of months to comply with last year's OPEC+ deal. Some of its older facilities, have since struggled to recover, according to London-based consultant Energy Aspects.

U.S. shale producers restrain output, even at higher prices

(Reuters; June 28) - Even with oil surging toward $75 a barrel, U.S. shale producers are keeping their pledges to hold the line on spending and keep output flat, a departure from previous boom cycles. This year's run-up in crude prices, along with oil output curbs imposed by the OPEC+ producers group, historically would have triggered a drilling boom. But investors are demanding financial returns over more volume and financiers are shifting to renewables, so shale firms are determined to stay disciplined.

"I'm still confident the producers will not respond" to the run-up in prices, said Scott Sheffield, chief executive of Pioneer Natural Resources, the largest producer in the Permian Basin shale field. A focus on shareholder returns has kept spending low, he said. Last week benchmark U.S. crude futures traded above $73 a barrel, the highest since October 2018. Back then there were 1,052 U.S. rigs drilling but today there are much less than half that many, about 470, according to Baker Hughes data.

U.S. shale output remains well below the January 2020 peak of 9.18 million barrels per day, with production from the seven largest fields this month running 7.77 million barrels per day, or 15.4% below January 2020, according to U.S. government data.

Oil companies reduce their inventory of uncompleted wells

(Houston Chronicle; June 28) - Oil companies are drawing down their inventory of unfinished wells as they put off new drilling to satisfy investors who want to see financial discipline after the pandemic-driven oil bust. The Energy Department estimates that the U.S. inventory of wells that were drilled but unfinished has declined by 27% to 6,521 from a peak of 8,874 in June 2020. Nearly 40%, or 2,616, of the so-called drilled-but-uncompleted wells, are in the Permian Basin of West Texas and eastern New Mexico.

Shale drillers keep an inventory of wells that are drilled but not completed to maintain a buffer of wells they can bring online as production declines from existing wells. The inventory of such wells allows shale drillers to maintain steady production as output from individual wells can decline by as much as 60% to 70% after a year. During the global pandemic, companies stopped drilling new wells and stifled output from existing wells as oil demand and prices plunged. When demand returned, drillers mostly turned to uncompleted wells to boost production more cheaply than drilling new wells.

Oil analysts are keeping an eye on drilled-but-uncompleted wells. When the inventory is depleted, oil companies will have to start drilling more wells to maintain production, said Karr Ingham, a petroleum economist with the Alliance of Energy Producers. The number of new wells could rebound in the second half of the year as the inventory of uncompleted wells continues to decline, Ingham said.

Norway's biggest bank not ready stop oil and gas financing

(Bloomberg; June 28) - The top banker in western Europe's biggest oil producer said she is ready to fight the growing number of activists pressuring her to stop funding the petroleum industry. Kjerstin Braathen, CEO of Norway's biggest bank, DNB, said fossil-fuel divestment and exclusion are "dangerous" ways to try to reduce carbon emissions. Her main argument is that cutting the flow of cash to Norwegian producers would allow less scrupulous actors to step in, ultimately impeding the transition to sustainable fuels.

"It could be a dangerous strategy if the result is that we are building up more gray markets that are not regulated, that are not transparent, that aren't impacted by regulation," Braathen said. There is evidence to suggest that companies that end up on exclusion lists easily find new sources of finance, she said. A variety of funds, including some of the world's biggest, already are stepping in to fund projects as banks pull out, often buying portfolios at a discount.

More than two decades since the world agreed to adopt the Kyoto Protocol in an effort to fight global warming, there remains disagreement over how best to reform polluters. Asset managers and banks are still deciding whether to pressure the worst emitters from the inside, or exclude them from financing altogether. Braathen said the Norwegian producers that DNB finances have proved that they can cut emissions more than their competitors. Norway's biggest oil producer, state-backed Equinor, has abandoned shale and plans to cut its net-carbon intensity by 40% by 2035.

Aging oil and gas wells a nationwide problem

(Bloomberg; June 29) - Ashley Watt is nothing if not a friend of fracking. She's invested in mines that supply the sand that frackers blast into the ground. Her family owns a ranch larger than Manhattan in Crane County, Texas, that's home to hundreds of oil and gas wells. Her Twitter handle is "Frac Sand Baroness." That's what made it all the more jarring almost three weeks ago when Watt began publicly railing against one particular oil driller for leaks on her land. Noxious wastewater from oil drilling began leaching across the ground, endangering people and killing livestock.

Chevron, which drilled the 1960s-era wells that polluted Watt's land, brought in earth-moving equipment and a well-control crew, even though it had sold most of its interests there years ago. It took 10 days to halt the first leak. Given the hundreds of other aging wells dotting the land, it's done little to put Watt's mind at ease. "I am not anti-oil industry," Watt said. "That is the economy here. It's a good business."

At the same the same time, she said, "We have to be responsible stewards. If we can't do it right here in the Permian Basin, then how can we do it right anywhere?" And just like that, Watt — whether she likes it or not — became an ally to scores of activists who have been warning for years that America is on the verge of an environmental disaster. Long before the advent of shale drilling, conventional explorers left the country pierced with millions of defunct wells that are aging by the day and increasingly springing leaks.

There are 3.4 million old oil and gas wells in various states of abandonment across the U.S., an almost 20% increase in the past decade, according to the Environmental Protection Agency. Less than half have been plugged, EPA figures showed.

Saskatchewan faces costly number of orphaned wells

(Global News; June 28) - A single insolvent oil company from Alberta has created a five-fold increase in the number of orphaned wells to shut down and seal in Saskatchewan — and has left $31 million in cleanup costs and unpaid bills. Calgary-based Bow River Energy, which sought bankruptcy in late 2020, has 671 orphaned oil and gas sites in west-central Saskatchewan, said the provincial Ministry of Energy and Resources.

The ministry said it is the largest group of sites from a single company taken into the province's Orphan Well Fund, and could cost up to $25 million to clean up over two to three years. In addition, a long list of creditors is owed more than $6 million, including farmers, ranchers, small businesses, First Nations, rural municipalities, and the province.

It may be just the tip of an expensive iceberg, said industry expert Ken Gordey, who spent the first half of his career developing fields and now the latter half cleaning them up. "It should have never got to this point. We have to turn around and do a refocus here," he said. It's a big problem in Saskatchewan, with some 75,000 abandoned or inactive wells, said Bill Kilgannon, executive director of University of Alberta's Parkland Institute, which studies the industry in western Canada. Many wells are owned by small companies that buy properties from major oil companies as the wells decline.

[Report says Alberta should take over marginal wells for cleanup]

(The Canadian Press; June 29) - Most of Alberta's wells no longer hold enough oil and gas to pay for their cleanup and the public should take them over to ensure any revenue funds remediation, a new report concludes. "It is a radical idea," said Regan Boychuk of the Alberta Liabilities Disclosure Project, which produced the report. Using data from the Alberta Energy Regulator released under Freedom of Information legislation, the report estimates the cleanup cost for the province's 300,000 unreclaimed wells at somewhere between $40 billion and $70 billion — which doesn't include pipelines or pump stations.

The Disclosure Project, which has followed the issue for years and has advised academics and government, concludes there may not be enough value left in the ground to fund the work. The same data set from the regulator suggests that 80% of Alberta's operating wells no longer hold enough oil and gas to pay for their own remediation. It also says that by the regulator's own standards, 49% of oil and gas companies licensed by the regulator are insolvent, their assets outweighed by liabilities.

Still, those companies retain wells that pump and earn revenue. The report suggests creating an agency to step in on insolvent companies, operate whatever wells remain, and use the proceeds to fund remediation. As it is now, Boychuk said, the public pays the bills. Between government grants to fund reclamation, unpaid taxes and overdue lease payments to landowners, the report says Canadians subsidize energy cleanup at $4.3 million a day. "Polluting companies must pay for their own cleanup," he said.

[Biden administration backs coastal city’s fight against oil line]

(Bloomberg; June 29) - A small coastal city in Maine has won the support of the Biden administration in its fight against a Canadian oil pipeline in what environmentalists see as a signal that other pipelines could face similar treatment. In a brief filed with the U.S. First Circuit Court of Appeals on June 28, the federal government said that a South Portland ordinance that would effectively prevent crude exports by prohibiting the transfer of crude onto marine vessels is not preempted by federal laws.

The picturesque city on the Atlantic is the injection point for a seldom-used, World War II-era oil pipeline that carries crude from the Maine coast to Montreal-area refineries. The Portland Pipe Line Corp., exclusively owned by Suncor Energy, has been trying to reverse the line for more than a decade so it can export Canadian crude to foreign markets. But the city wants to prevent the reversal amid concerns exporting crude oil would threaten waterways and air quality.

Environmentalists said the filing in support of South Portland signals that the Biden administration may not stand in the way of other local authorities battling oil pipelines through local ordinances. “The Biden administration underscored in a new legal filing that federal law doesn't override a state or locality's decision about where an oil pipeline should be located," the National Wildlife Federation said in a release.

Outlook dims for carbon-capture efforts at coal plants

(S&P Global Platts; June 25) - Carbon capture at aging U.S. coal plants has always been a long shot financially, and the outlook for such projects appears to be dimming as private investors look elsewhere and federal support for the technology wanes under the Biden administration. None of the five proposals to retrofit U.S. coal plants with carbon-capture technology has secured funding to construct the scrubbers, carbon absorbers, and geologic storage sites needed to begin operations.

Some analysts also warn that costs could escalate, ultimately leaving ratepayers and taxpayers responsible for runaway expenses should projects be abandoned. The $1.4 billion carbon-sequestration facility planned for the 847-megawatt San Juan Generating Station in New Mexico, for example, is two years behind schedule. Enchant Energy, the company championing the project, says it will need a $906 million loan guarantee from the U.S. Department of Energy and another $90 million in debt financing from the U.S. Department of Agriculture's Rural Utilities Services program to continue development.

Whether such public financing will materialize is uncertain. The Department of Energy under President Joe Biden is shifting carbon-capture research and development money away from coal plants and to gas-fired power plants and hard-to-abate industries such as cement manufacturing. Meanwhile, private funding for costly carbon-capture projects is drying up as banks and equity firms adopt policies discouraging coal investments.

Smaller oil sands sites churn out more emissions per barrel

(Reuters; June 28) - In the shadow of Canada's bigger oil sands projects, smaller, technologically outdated facilities are spewing up to three times more emissions per barrel than the sector's already high average. These projects present a challenge to Canada's goal to cut emissions 40% - 45% by 2030. With oil prices near 2½-year highs and dim prospects for new projects in a world heading to net-zero emissions, owners are aiming to pump dry existing facilities, including the most carbon-intense sites.

Prime Minister Justin Trudeau's government is slowly ramping up a national carbon price from C$40 per tonne of carbon dioxide equivalent to C$170 by 2030. Those costs may eventually make the sites uneconomic, but until then, producers are after maximum benefit from rebounding oil prices. "These assets are flying under the regulatory radar and they might for a while," said Andrew Logan, senior director of oil and gas at shareholder advisers Ceres. "In a rational world, these assets wouldn't be producing."

Canada has the highest emissions per barrel of oil equivalent among the top 10 global producers, according to consultancy Rystad Energy. Canadian Environment Minister Jonathan Wilkinson said the government has addressed some concerns about high-intensity sites, such as tighter methane regulations and an incoming standard for lower-carbon fuels, but said it needs to do more. For producers, the cost of cutting emissions is higher than the carbon price, and operating costs are low, so it's it worthwhile to keep running the sites, said Chris Severson-Baker, Alberta director for the Pembina Institute.

U.S. producers hope buyers will pay more for 'greener gas'

(Reuters; June 30) - U.S. natural gas producers hope climate-conscious electric utilities and gas exporters will pay a premium for what they say is "greener gas" that has been certified as coming from low-emission operations or from renewable sources such as landfills. EQT Corp., Chesapeake Energy and liquefied natural gas producers Cheniere Energy and NextDecade are among the companies considering low-carbon certifications from groups such as Denver-based Project Canary.

Gas certified as "responsibly produced" and contributing less emissions could get up to 5% above market prices, or up to 15 cents per thousand cubic feet, proponents say. So far not many customers have been willing to pay the premium — a problem for firms trying to sell lower-carbon versions of fossil fuels. Some European buyers have shunned U.S. shale gas and several U.S. cities including New York and San Francisco have sought to ban new residential gas connections over environmental concerns.

"When you're talking about trillions of cubic feet of global gas production, mere pennies in price movement can make all the difference between profitability and losses," said Kentaro Kawamori, chief executive of Persefoni, which develops tools to measure a company's carbon footprint. Utilities, the biggest gas buyers, have endorsed net-zero emissions targets, "but it is not being translated into procurement departments," said Chris Kalnin, chief executive of U.S. shale gas producer BKV Corp.

Qatar forecasts steady LNG demand growth to 2040

(Bloomberg; June 28) - Natural gas giant Qatar Petroleum has predicted global demand for the fuel will continue to climb for almost two decades, a far more optimistic outlook than the International Energy Agency. QP expects gas consumption to grow at a rate of 1.5% a year, driven by economic growth and a broad shift away from dirtier-burning coal, according to a Qatar Petroleum bond prospectus seen by Bloomberg. It sees demand peaking around 2040, roughly 15 years later than forecast by the IEA.

The world's largest producer of liquefied natural gas is spending tens of billions of dollars to expand its output, betting on a rosy future for the commodity. Gas has been seen as a key transition fuel in the global shift to cleaner energy, though it's falling out of favor with some governments as they accelerate efforts to slow climate change. The IEA expects gas demand to peak in the mid-2020s, according to its "Net Zero by 2050" report published in May. By mid-century, gas use will be 55% lower than in 2020, it said.

QP's outlook contrasts sharply. The state producer expects LNG demand to grow even after gas consumption starts to decline, saying falling gas production in some countries will raise demand for imports. It sees the LNG market growing at a rate of 3.6% a year to 2040, and continuing to expand until 2050. Qatar is significantly ramping up its output, while dropping prices to squeeze competitors out the market. Qatar Petroleum's capital spend will total almost $60 billion 2021-2025, according to the bond prospectus.

Sempra, Saudi Aramco part ways over Texas LNG project

(S&P Global Platts; June 29) - Sempra's efforts to finalize a long-term deal with Saudi Aramco to support the proposed Port Arthur LNG export terminal in Texas have fallen through, an executive said June 29 in what amounts to a setback following several delays in advancing the project. During Sempra's annual investor-day presentation to analysts, Justin Bird, the head of its LNG business, said Sempra and Aramco mutually agreed to let their 2019 preliminary agreement expire.

The deal, as originally announced, called for Aramco to take a 25% stake in Port Arthur LNG and off-take 5 million tonnes per year of supply from the terminal. Aramco has been adjusting its gas ambitions the past two years amid the coronavirus pandemic and volatility in global gas markets. Bird cited the reevaluation by the state-owned oil company in the context of why the deal between Sempra and Aramco was not finalized.

During his own remarks, Sempra CEO Jeffrey Martin said the company's Energia Costa Azul liquefaction project in Mexico, which is under construction, is its top infrastructure priority, and that a proposed expansion at its Cameron LNG export terminal in Louisiana has leapfrogged Port Arthur LNG in terms of priority. In May, Sempra said it would likely further delay a final investment decision on Port Arthur LNG to 2022, as it continues to face commercial challenges for the project planned at 11 million tonnes per year.

Cheniere gets OK to send gas into newest LNG train at Sabine Pass

(Reuters; June 29) - U.S. energy regulators gave Cheniere Energy permission to take steps needed to put the sixth liquefaction train at the company's Sabine Pass LNG export plant in Louisiana into service. The Federal Energy Regulatory Commission approved Cheniere's request to introduce gas and commission the Train 6 system.

Cheniere has said Train 6 will enter commercial service in 2022 but analysts note the unit will likely start producing LNG in test mode later this year. Cheniere is the biggest LNG producer in the U.S. and is also the country's biggest buyer of natural gas. In addition to Sabine, which will have the capacity to produce about 30 million tonnes per year of LNG after Train 6 enters service, Cheniere also owns and operates the three-train Corpus Christi LNG export plant in Texas, at 15 million tonnes annual capacity.

Cheniere started in the LNG import business more than a decade ago, before shale gas overwhelmed the U.S. market and halted the need for imports. The company successfully pivoted to the business of liquefying domestically produced gas for export to customers overseas, building itself into a major supplier in global markets.

Indigenous-led LNG projects latest hopefuls in British Columbia

(Financial Post; Canada; June 30) - After a string of canceled liquefied natural gas export projects in British Columbia, a pair of new proposals led by Indigenous groups is reinvigorating hope that additional Western Canadian gas exports to Asia could move ahead. The Nisgaa Nation, whose traditional territory is north of Prince Rupert near the Alaska border, and a Calgary-based consortium of gas producers called Rockies LNG Partners, plan to file a project description for the Ksi Lisims LNG project this summer.

Information that the Nisgaa Nation sent to its members outlines the scope of the project, which would be a floating liquefaction facility capable of producing 12 million tonnes per year. It would be located near the coastal village of Gingolx, just a few miles south of the Alaska border. The other indigenous-led project is Cedar LNG, which is being pushed by the Haisla Nation. It also would be a floating installation, proposed at 3 million tonnes per year export capacity and a capital cost of C$3 billion. The partners hope to reach a project sanctioning decision on Cedar LNG by 2023.

The Shell-led C$40-billion LNG export project in Kitimat is the only project on Canada's West Coast that has secured final investment decision from its backers. Woodfibre LNG, a smaller project located in Squamish, British Columbia, is awaiting a final approval from its Singapore-based owner Pacific Oil & Gas Group. The projects are the only two survivors after a string of canceled multibillion-dollar LNG export projects.

Louisiana LNG developer wants to produce its own gas

(S&P Global Platts; June 29) - Tellurian will consider a "business combination" to ensure it has sufficient gas reserves to support its proposed Driftwood LNG export facility in Louisiana, Executive Chairman Charif Souki said June 29 in a podcast to employees and investors. The plan follows the company's announcement in March that it wants to produce all the gas it will need to feed Driftwood and would not sanction the project until it had secured sufficient upstream reserves for the first phase of the project.

To get there, Tellurian needs to get bigger in the upstream, and faster, even as it drills more wells in the Haynesville Shale on its own acreage and in partnership with others. Those efforts alone are expected to almost triple Tellurian's output by the end of 2021 — to 80 million cubic feet a day — compared with the end of 2020, Souki said. "Clearly, this is not sufficient," he said. "We are in a position now to start looking seriously at a business combination that will make sense for our integrated business model."

Souki did not provide any further details. The developer is looking at building Driftwood in phases, starting at 16 million tonnes per year production capacity. Tellurian is targeting to give Bechtel a notice to proceed with construction of the terminal by the end of the first-quarter 2022. After a two-year lull in firm commercial activity, Tellurian signed 10-year sales and purchase agreements in May and June with commodity traders Gunvor and Vitol for a combined 6 million tonnes per year of Driftwood production.

Freeport LNG in Texas says it could decide on expansion in 2022

(S&P Global Platts; June 29) - Freeport LNG could sign sufficient long-term contracts by the end of the year to proceed with a fourth liquefaction train at its Texas export facility, based on advanced talks with potential buyers, CEO Michael Smith said during a June 29 interview. While the company has not announced any firm commercial deals since a preliminary agreement signed in 2018 by Japan's Sumitomo expired last year, talks with potential buyers have picked up recently amid tightness in global supplies, Smith said.

If it gets at least 75% of the train's 5 million tonnes per year capacity sold to commodity traders, utilities, and other end-users, that would allow the company to make a final investment decision by the summer of 2022, Smith said. "I think it is only a matter of time before customers will be willing to sign 20-year deals to facilitate new FIDs."

Freeport went online with its first three production trains 2019-2020, with capacity to produce up to 15 million tonnes per year. The export project, reported at $13.5 billion, was built at the site of Freeport’s underused LNG import terminal.

Offshore Louisiana LNG developer asks FERC for another extension

(Reuters; June 30) - Delfin LNG has asked federal regulators for a third extension, until September 2022, to bring into service the onshore facilities of its proposed floating LNG export plant off the coast of Louisiana. The Federal Energy Regulatory Commission in 2017 authorized Delfin to build its project by September 2019. In June 2019, Delfin asked FERC for an extension until March 2023 to finish the project. FERC, however, only gave Delfin a one-year extension, until September 2020. In June 2020, Delfin received another one-year extension to finish the project by September 2021.

In asking for this third extension, Delfin said global "economic conditions are recovering from the COVID-19 pandemic and the spot and short-term markets for LNG have significantly improved ... which will support the company to enter into long-term LNG offtake contracts." Delfin is one of more than a dozen North American LNG projects that have repeatedly pushed back decisions to start construction due primarily to a lack of customers signing long-term deals needed to finance the multibillion-dollar facilities.

Delfin's project would use existing offshore pipelines to supply gas to up to four liquefaction floating factory ships to produce up to 13 million tonnes per year of LNG.

Expensive spot-market LNG curbs gas use in China

(S&P Global Platts; June 30) - High spot LNG prices and low margins have prompted southern China's gas-fired power plants to lower their utilization rates and review their exposure to the short-term LNG market, after they had ramped up electricity production in May and June to ease tight power supply. Many gas importers have already gone to the sidelines as negative margins in power and truck-delivered LNG markets have reduced appetite for costly spot LNG cargoes.

Gas distributors like Guangzhou Gas have indicated that fuel demand from gas-fired power plants has weakened as LNG prices have touched levels that many plant operators cannot afford. Shenzhen Energy, which runs four to five gas-fired power plants in Guangdong province, has cut the operating rate of these plants to an average 50% to 60%. The spot LNG price has surged past $12 per million Btu, making electricity much costlier than the government-set rates that gas-fired power plants can charge.

The power generation costs of gas-fired power plants are mainly determined by the price of gas, while the price of the electricity sold to the grid is regulated by the government — making it difficult to pass on higher fuel prices to end-users. Many power plants were operating at half their capacity, as only around half of their gas feedstock was secured under long-term contracts that are cheaper than spot volumes.

Companies continue investing in additional Norwegian oil production

(Reuters; June 30) - Equinor and Aker BP set out plans to develop four oil and gas discoveries with a total price tag of 14.5 billion Norwegian crowns ($1.69 billion) as part of Norway's efforts to maximize output from existing fields. The nation, which began to extract oil and gas 50 years ago, believes it has only pumped about half of its available resources and hopes near-field developments will help secure output for years to come.

In one such development, Equinor, Petoro, Eni, and TotalEnergies will invest 6.5 billion crowns in two oil and gas discoveries near the Kristin gas and condensate field in the Norwegian Sea, the companies said. The overall expected production of oil and gas from the two developments was estimated at 58.2 million barrels of oil equivalent over the field's lifetime. Production from the first three wells is scheduled to start in 2024. The start for the two last wells is planned for 2025, and additional discoveries may be added.

Separately, Aker BP and partners ConocoPhillips and Lundin Energy will invest 8 billion Norwegian crowns ($935 million) to develop the Kobra East and Gekko oil and gas discoveries in the Alvheim area in the North Sea. The project aims to produce around 40 million barrels of oil equivalent at a break-even price of below $30 per barrel, with production expected to start in 2024, Aker BP told the Norwegian energy ministry.