Oil and Gas News Briefs
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UAE wants to sell as much oil as it can before world changes

(The Wall Street Journal; July 7) - Behind the standoff inside OPEC over whether to boost oil production is a key cartel member with a new strategy: Sell as much crude as possible before demand dries up. The United Arab Emirates' strategy represents one of the most significant shifts in oil policy by a major Mideast petrostate. For years the region's oil-producing governments said they weren't worried about finding oil buyers far into the future. The UAE, which holds some of the world's largest untapped crude reserves, is breaking from that orthodoxy, according to people familiar with the strategy.

"This is the time to maximize the value of the country's hydrocarbon resources, while they have value," said a person briefed on the UAE strategy. "The aim of the investment is to generate revenue for the diversification of the economy, both for investment in new energy and, as importantly, in new revenue streams." The country isn't worried about a sudden demand drop, and expects to have buyers for decades. However, people familiar with the new tack said the country wants to pump and sell as much as it can now, when demand and prices are strong. Proceeds will help it wean its economy off oil.

"Market share is a key factor here," said a senior UAE oil executive. "We want a bigger market share, to monetize as much as we can from our reserves, especially when we have spent billions developing them." The UAE has been the lone holdout regarding a deal to boost crude output among members of OPEC and its allies, together known as OPEC+. "The historic alliance (because the UAE and Saudi Arabia) is being tested," said Christyan Malek, who is in charge of global energy at JP Morgan & Chase. "The rivalry is no longer just in the oil market, but for the post-oil economy."

Ill-timed hedging bets cost U.S. oil producers billions

(Financial Times; London; July 7) - Some of America's biggest oil groups are racking up tens of billions of dollars in hedging losses despite soaring crude prices, as contracts signed during last year's crash leave them selling their output at deeply discounted prices. Oil is trading near six-year highs of around $75 a barrel, but almost a third of the 11 million barrels a day of U.S. production is being sold for just $55 a barrel, according to IHS Markit, a global market consultancy.

The figures will offer comfort to the OPEC cartel that rallying prices are not about to spark another market-busting surge in U.S. shale production. "OPEC gets a pass to keep lifting prices right now if it wants to without fearing much of a U.S. supply response," said Bill Farren-Price, an analyst at Enverus. "Shale producers are locked into selling their oil cheaply this year." IHS Markit said U.S. oil-hedging revenue losses in the first half of 2021 had already hit $7.5 billion, but would rise by an additional $12 billion if crude remains at $75 a barrel until the end of the year.

Many of the hedges were signed during the worst months of last year's crash, when creditors demanded that companies buy insurance against further price drops. In the wake of vaccination breakthroughs and OPEC's output cuts since then, those hedges now look far too pessimistic. "If you get hedging right, people don't give you credit for it. If you get it wrong, you get hammered," said Raoul LeBlanc, an IHS vice president. "They missed the boat this year." JPMorgan analysts said surging oil prices in recent months have left almost all the hedges made by the companies it covers underwater.

U.S. shale companies show restraint as they cash in on higher prices

(The Wall Street Journal; July 9) - Shale companies pumped with abandon whenever oil prices rose sharply last decade. But as crude tops $70 a barrel, they are barely doing enough to sustain U.S. production. Frackers have been forced to rein in spending and live within their means after many investors lost faith in the companies following years of poor returns, lenders reduced their credit lines and capital markets showed little interest in funding expansive new drilling campaigns.

The result is that shale drillers, which in the past have played the role of the oil world's swing producer by quickly increasing output to meet demand, are largely standing pat for now, as the reopening of Western economies leads to a resurgence of global oil and gas prices. Meanwhile, the companies are raking in more cash than ever. Public shale companies that drill primarily for oil collectively generated a record $4.1 billion in free cash flow in the first quarter of 2021 and are poised to take in almost $15 billion for the year if prices remain higher, according to consulting firm Rystad Energy.

But instead of pumping that money back into drilling, producers have said they plan to focus on reducing debt, keeping output flat. Even as oil prices reached their highest level in six years last week, many drilling rigs remain idle. The U.S. is producing roughly 2 million barrels a day less than it was before the pandemic. The number of active rigs drilling for oil stands at 376, down from 683 pre-COVID-19, said oil-field services firm Baker Hughes. If shale companies don't add more rigs, U.S. production could fall by the end of the year, said Shaia Hosseinzadeh, of OnyxPoint Global Management.

California denies new fracking permits, citing climate issues

(The Associated Press; July 9) - California denied 21 oil drilling permits this week in the latest move toward ending fracking in a state that makes millions from the petroleum industry but is seeing widespread drought and more dangerous fire seasons linked to climate change. State Oil and Gas Supervisor Uduak-Joe Ntuk sent letters July 8 to Aera Energy, denying permits to drill using hydraulic fracturing in two Kern County oil fields to "protect "public health and safety and environmental quality, including (the) reduction and mitigation of greenhouse gas emissions."

Aera Energy, a joint venture Shell and ExxonMobil, called the denials disappointing though not surprising. "This is the latest decision attacking the oil and gas industry that is based solely on politics rather than sound data or science," Aera spokeswoman Cindy Pollard said July 9, adding that the company was evaluating its legal options.

"In the face of the effects of the climate emergency, the risks to everyday Californians are too high to approve these permits," Ntuk said July 9 in emails to newspapers. Gov. Gavin Newsom in April directed the state regulators to develop a plan to stop issuing new fracking permits by 2024 after a bill to ban fracking died in the Legislature. Newsom also has ordered the California Air Resources Board to figure out how the state can end all oil production by 2045. Those decisions would make California the largest state to ban fracking and likely the first in the world to set a deadline for ending oil production.

Oil sands CEOs say they need government aid to reduce emissions

(Bloomberg; July 8) - It will cost about C$75 billion (US$60 billion) to zero out greenhouse gases from oil sands operations by 2050 with a good deal of the costs borne by taxpayers and many loose ends yet to be tied up, according to two of the Canadian industry's top CEOs. To achieve the goal announced last month, about half of the emission cuts would need to come from capturing carbon at oil sands sites and sequestering it deep underground, which may require as much as two-thirds government capital, such as in Norway, said Mark Little, CEO of Suncor Energy.

It's still unclear how and when most of the projects will be implemented or which agreements will be needed, but it's clear the industry doesn't want to do it alone. "We haven't been able to find any jurisdiction in the world where carbon capture has been implemented, where the national government or the state governments are not very significant partners in that investment," Alexander Pourbaix, CEO of Cenovus Energy, said in the same interview "I don't think any of us would ever be in a position to go at this on our own. It's just too significant an undertaking."

The initiative follows mounting pressure from large, climate-minded investors, many of which have ditched their oil sands holdings. Sitting atop the world's third-largest crude reserves, the Canadian industry uses carbon-intensive extraction methods that have made it a target of environmentalists. At stake are jobs and tax revenues from an industry that represents about 10% of the Canadian economy. “We have one Achilles heel: It’s greenhouse gas emissions,” Little said. “We can bury our heads in the sand and become a victim, or we can actually deal with it.”

University of Calgary suspends oil and gas engineering program

(CBC News; Canada; July 8) - For more than two decades, the bachelor's program in oil and gas engineering at the University of Calgary was popular with students seeking a career in energy — and maybe a job in one of the office towers downtown. But after a long downturn in the oil patch, enrolment at historic lows, and the energy landscape changing, the university's engineering school is suspending admission of new students to the undergraduate program. Existing students will be able to complete their degree.

"It's really been a great program for us; it typically used to be a high-demand program," said Arin Sen, head of the department of chemical and petroleum engineering. "It wasn't a decision that we came to lightly." The university said it has no plans to abandon oil and gas studies. Sen said there are still various paths for engineering students to pursue careers in oil and gas, including a minor in petroleum engineering or graduate studies among any number of options.

The oil and gas engineering undergraduate program at the university was one of several routes students could follow to a career in the petroleum sector, including chemical, mechanical, and civil engineering. Typically, about 40 students would enter the program each year, but it graduated fewer than 10 last year. The university began a review of the program and — following consultations with students, alumni, faculty, and industry — received provincial approval to suspend it.

Biden administration conflicted on LNG exports, analyst says

(E&E News; July 8) - U.S. liquefied natural gas exports are surging under President Joe Biden, setting records and poised to climb higher. Even as the administration pledges to tackle climate change in part by distancing the U.S. from fossil fuels, the country's LNG exports hit a new high in March, according to U.S. Energy Information Administration data. The increase highlights a challenge for Biden, who faces pressure from the left flank and environmental groups for a hard pivot from fossil fuels, even as gas supporters say the fuel would help cut global emissions by shifting countries away from coal.

Industry representatives worry that mixed messages or lukewarm support at the federal level could lead overseas buyers to question the U.S. commitment and turn elsewhere for gas. The administration could do a better job of defining how LNG fits into its goals, said Anna Mikulska, a fellow in energy studies at Rice University's Baker Institute. At times, comments from senior officials like Energy Secretary Jennifer Granholm and U.S. climate envoy John Kerry appear to conflict with each other, Mikulska said.

Kerry set off alarms within the industry in January when he warned in a speech to the World Economic Forum that if the globe continues to build infrastructure for gas, "we're going to be stuck with stranded assets in 10 or 20 or 30 years." By contrast, Granholm has said U.S. LNG exports are often sent to "countries that would otherwise be using very carbon-intensive fuels." That the Biden administration hasn't said more about LNG is likely a by-product of the tension between his climate-conscious agenda and the reality that LNG, while cleaner than coal, is still a fossil fuel, experts said.

New Jersey LNG export terminal faces multiple hurdles

(Delaware Currents; July 8) - A contentious plan to export liquified natural gas from a Delaware River port faces new political, economic and environmental headwinds that raise questions about its future. A new White House administration, a global market that has considerably cooled in the past two years and pandemic-related workforce disruptions have all cast long shadows over the private-developer proposal.

The project would start with fracked gas piped from the Marcellus shale region of Pennsylvania to a liquefaction plant about 50 miles northwest of Scranton. The LNG would be sent by truck and rail 180 miles away to a port in New Jersey, southwest of Philadelphia, for export. The project would have an average production capacity of about 300 million cubic feet per day of natural gas.

The company has said that it expects the $800 million project to be operational in the first quarter of 2022, but work on the terminal site has been on an extended pause. The U.S. Pipeline and Hazardous Materials Safety Administration, which issued a special permit in late 2019 for rail transport of LNG, has proposed suspending the authorization pending completion of research and an external review by technical experts.

Meanwhile, 15 state attorneys general and five environmental groups have challenged the rule allowing LNG transport by rail. In addition, the company and opponents are waiting on the Federal Energy Regulatory Commission to decide whether it will assert its jurisdiction over the development, which could set off lengthy environmental assessments to consider the ecological, cultural, and human impacts of the project.

[Critics want to draw attention to growing number of orphaned wells]

(S&P Global Platts; July 9) - A growing number of orphaned and abandoned wells in the U.S. is growing costlier by the day, challenging an oil and gas industry that is already negotiating the energy transition away from fossil fuels, according to critics, who are calling for reforms and new funding to clean up long-dormant, corroding sites. The White House is aiming to inject major cash into well-plugging activities, and new groups in Texas, such as Commission Shift, have sprung up this year to help lobby and draw attention to the potential ticking time bombs of orphaned or undocumented wells.

The Permian Basin has become dotted with more unnaturally occurring phenomena, including sinkholes and a so-called “lake” from failed wells drilled decades ago. There is also the fear that new drilling and hydraulic fracturing — as well as saltwater disposal wells — increasingly will interfere with and rupture older well sites, threatening air quality and water supplies often without any visible problems above the surface, said Virginia Palacios, executive director of the new Commission Shift group focused on reforming and better funding Texas regulators that oversee oil and gas laws.

Spurred by the shale revolution and led by Texas, U.S. oil production boomed from 5.5 million barrels per day in 2010 to a record high of nearly 13 million at the beginning of 2020, although output has since slipped to about 11.3 million. But that surge in growth has not come without cyclical stops and starts, and with each downturn came a wave of bankruptcies and consolidation. "When these companies go bankrupt, we see more orphan wells going to the state to plug and clean up," Palacios said. The Interstate Oil & Gas Compact Commission adds up about 57,000 documented orphan wells nationwide.

[Global share of LNG sold at gas-on-gas pricing continues to increase]

(S&P Global Platts; July 8) - The share of gas-on-gas LNG pricing in the global market rose by one percentage point in 2020 to reach 49.3%, according to the latest pricing survey by the International Gas Union published July 8. This, the IGU said, was largely driven by a "significant" shift in LNG imports to gas-on-gas pricing and away from oil-price-indexed contracts. "The rise in gas-on-gas LNG imports in 2020 reflected another sharp rise in spot LNG cargoes," it said in the report.

The IGU has carried out its wholesale pricing survey since 2005, with responses covering 98% of world consumption. The rising trend in gas-on-gas pricing in LNG imports is a continuation of the movement over the past three years, it said. "The total gas-on-gas pricing share of LNG imports in 2016 was 25% and in 2020 that had risen to 44%," it said. "The rise between 2016 and 2018 was all due to rising spot LNG imports, while in 2019 the increase was partly spot LNG imports and the rush of LNG to Europe's traded markets. In 2020, the increase was due to rising spot LNG cargoes."

The IGU added that the impact of COVID-19 on the global gas market, while stalling LNG demand, did not appear to have slowed the rise in spot LNG imports. While gas-on-gas pricing globally continues to increase, the IGU said oil indexation retained its share of overall global gas demand at around 18.5% due to a switch toward oil indexation and away from regulated pricing in some countries. China is the largest oil-indexed pipeline gas importer with gas from Central Asia, Myanmar, and Russia.

Report recommends steps for gas producers to reduce emissions

(CBC News; July 8) - As the world's economy rebounds from the COVID-19 pandemic, demand for oil and gas is set to increase — and so is the emission of methane, a potent greenhouse gas with 80 times the heat-trapping power of carbon dioxide. The fossil fuel industry is one of the biggest sources of human-generated methane emissions. Now for the good news: About 40% of methane emissions from oil and gas production can be eliminated at a low cost, the U.S. Energy Information Agency said in a report.

Cutting down that number "is among the most cost-effective and impactful actions that governments can take to achieve global climate goals," according to the agency. Because the gas is invisible and odorless, detecting leaks can be challenging. And leaks can occur at any point in the process--from extraction out of the ground to the moment where the gas is burned in a power plant. Among the most cost-effective steps gas producers can take is replacing old equipment, the EIA said.

Many pumps, valves, and compressors on a gas-drilling pad emit methane in the course of their operations, and tend to emit more as they age — especially if they aren't maintained. The EIA recommends replacing components early and replacing gas-powered parts with electrified versions, which leak less gas in their operations. Detecting leaks early and often, through technology such as infrared cameras or satellite imaging, can also help plug leaks. These recovery steps all result in gas producers having more product to sell, so they tend to be more valuable for the industry.

Abu Dhabi joins Gulf nations in looking toward hydrogen exports

(Bloomberg; July 8) - Abu Dhabi is seeking investors to help build hydrogen export facilities, as Middle Eastern oil producers step up plans to sell what’s seen as a crucial fuel in the transition to cleaner energy. Abu Dhabi National Oil Co., which pumps almost all the oil and gas in the United Arab Emirates, is in talks for energy companies to buy equity stakes in the nation’s hydrogen projects, according to sources. It also aims to sign long-term sales contracts before pushing ahead with the investments, they said.

The market for hydrogen is tiny today but could be worth as much as $700 billion annually by 2050, according to Bloomberg New Energy Finance. Projects to export the fuel — which only emits water vapor when burned — are likely to cost billions of dollars. But amid a global push to slash greenhouse-gas emissions, Persian Gulf nations such as the UAE and Saudi Arabia are looking to hydrogen to reduce their reliance on oil.

Abu Dhabi's national oil company has signed agreements to explore sales of the fuel with Japan's government and Korea's GS Energy. Other state-owned firms in the Gulf want to turn their expertise in exporting liquid fuel into shipping hydrogen or ammonia to customers for electricity, transport and industrial use. Most of what Abu Dhabi exports is likely to be blue hydrogen, created by converting gas and capturing the carbon dioxide by-product. The hydrogen can be turned into ammonia to ship more easily.

Australia's LNG producers need to decide future role in hydrogen

(S&P Global Platts; July 9) - Australia's LNG producers are starting to test the waters for blue hydrogen, but the new fuel is yet to kick off in a big way and several factors will determine its growth trajectory and its place in the repertoire of the country's energy exports. So far, the biggest case for blue hydrogen, which is produced from reforming natural gas, has been that it could be the pathway for green hydrogen, which is produced from emissions-free electrolysis. Blue hydrogen has lower costs, the ability to scale up volumes quickly, and can use existing infrastructure for overseas transport.

For oil and gas companies, access to depleted acreage for storing carbon from the blue hydrogen process is an advantage, and it can give them a foothold with customers in Asia to grow the market. The stakes are high: Australian companies are in a race with peers in the Middle East that have pilot projects to scale up blue hydrogen, oil majors like Shell that are bringing in technological expertise to lower hydrogen costs, and proponents of green hydrogen that talk against transitioning through blue hydrogen.

There's also the question of whether Australian LNG companies will look to hydrogen as a substitute for LNG in the long run or just a diversification strategy. Companies face the dilemma of when to time their hydrogen investments, and when to decide between blue and green hydrogen despite the oil and gas sector advocating blue hydrogen as the low-hanging fruit for near-term decarbonization goals this decade. A lot will depend on what customers like Japan are willing to pay for, as some technologies require more investment on the producer end and others on the receiving end.

Asian LNG buyers look to avoid expensive spot-market gas

(S&P Global Platts; July 9) - LNG importers based in Asia have been actively seeking alternatives to meet incremental demand for the fuel during the summer season and to avoid costly spot-cargo procurement, with spot-market prices above that of legacy crude-linked contracts for most of 2021. These alternatives include exercising quality tolerance options with their long-term contract suppliers, adjusting their delivery schedule, or swapping cargoes for different delivery windows, volume or quality.

This marks a reversal in the spot-versus-legacy contract pricing dynamics from a year ago. Last year some Japanese importers were able to import a spot-market June or July delivery cargo at approximately $2 per million Btu, while other cargoes imported through long-term contracts linked to oil prices were hovering at $8 to $11 for the same months, customs data from the Ministry of Finance showed.

The spot and long-term LNG pricing dynamics have shifted dramatically from 2020 to 2021, with record lows to record spot-market highs recorded in a period of nine months amid tighter supplies. Currently, however, with spot LNG prices hovering above most long-term contract prices, importers are trying to maximize cargo purchases through their long-term cargoes, while minimizing their spot procurement.

Coal prices are on the rise amid strong demand

(Reuters column; July 8) - Seaborne coal has become a quiet winner among energy commodities, lacking the attention of higher-profile crude oil and liquefied natural gas, but enjoying strong gains amid rising demand. The prices for both thermal coal, used in power plants, and coking coal, used to make steel, have rallied strongly in recent months. And in both cases the driver has largely been China, the world's biggest producer, importer and consumer of the fuel.

There are two elements to China's influence on seaborne coal markets in Asia: Robust demand as the Chinese economy rebounds from the coronavirus pandemic; and Beijing's policy choice to ban imports from Australia. The real savior for Australian coal has been India, which imported a record 7.52 million tonnes of all grades in June, up from 6.61 million in May and more than triple from 2.04 million in June 2020.

Overall, it is clear China's stamp is all over the current rally in coal prices: Its strong demand is boosting Indonesian coal and its ban on imports from Australia is forcing a realignment of trade flows in Asia.