Oil and Gas News Briefs
Compiled by Larry Persily
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[Strong quake in Texas oil patch may prompt regulatory response]

(The Wall Street Journal; Nov. 19) - A powerful earthquake in West Texas is drawing fresh scrutiny to frackers' water-management operations in the nation's hottest oil and gas region. A 5.4-magnitude quake, the fourth-largest in state history, hit a production hot spot in Reeves County on Nov. 16, sending tremors felt as far as Dallas, El Paso and San Antonio, where it damaged a historical building. No injuries were reported.

The quake adds pressure on state regulators to stymie the Permian Basin's dangerous new seismic activity by imposing stricter rules on frackers' ability to pump wastewater underground, analysts and executives said. And it could prompt review of management practices and affect oil operations, they said. The quake was one of thousands to shake the oil-rich Permian of West Texas and New Mexico in recent years.

Scientists have linked the increase in seismic activity to companies pumping billions of gallons of wastewater — a byproduct of oil and gas production — down disposal wells. Water injections modify the pressure underground and can cause faults to slip and create earthquakes. The tremor was unlikely to have an immediate impact on production in the area, according to analysts. But some executives said it should be a wake-up call for regulators and companies to figure out how to deal with water disposal.

Kirk Edwards, an oil executive and former chairman of the Permian Basin Petroleum Association, said he felt this week's earthquake at his office in Midland, Texas, about a three-hour drive away from the site of the temblor. "We cannot keep cramming a tremendous amount of water through a disposal well at one site," Edwards said.

[Brent futures fall below $88; WTI down around $80]

(Bloomberg; Nov. 18) - Oil tumbled as everything from Wall Street sentiment to sagging demand for physical barrels of crude pointed toward a global economy headed toward a slowdown. Brent futures fell below $88 a barrel for the first time in about six weeks on Nov. 18 and West Texas Intermediate settled at around $80, the lowest since September. While Federal Reserve officials reiterated their resolve to continue raising interest rates and warned of pain ahead, lackluster demand among oil traders for crude this winter signaled a slowdown may already be underway in energy markets.

Crude bids have collapsed as the reality sets in that Chinese demand most likely gets worse before it gets better, said Rebecca Babin, a senior energy trader at CIBC Private Wealth Management. "Front -month time spreads — the backbone of tight markets —

are the weakest they have been since March 2021, signaling demand concerns are real and investors should be cautious when buying the dip."

While lower-than-usual inventories and geopolitical risks have led to occasional spikes, recessionary fears have weighed heavily on crude prices in the second half of this year. JPMorgan Chase projected the U.S. will enter a "mild" recession next year due to interest-rate hikes. Meanwhile, traders are keeping their eyes peeled on rising COVID cases in China as an indicator for crude consumption.

Qatar signs 27-year deal to supply China's Sinopec with LNG

(Reuters; Nov. 21) - QatarEnergy has signed a 27-year deal to supply China's Sinopec with liquefied natural gas, the longest such agreement so far as volatile markets drive buyers to seek long-term deals. Following Russia's invasion of Ukraine, competition for LNG has become intense, with Europe in particular needing vast amounts to replace Russian pipeline gas that used to make up almost 40% of the continent's imports.

"Today is an important milestone for the first sales and purchase agreement for North Field East project. It is 4 million tonnes for 27 years to Sinopec of China," QatarEnergy chief Saad al-Kaabi told Reuters in Doha, shortly before the deal signing. "It signifies long-term deals are here and important for both seller and buyer," he said, adding that the deal was the LNG sector's largest single sales and purchase agreement on record.

The North Field is part of the world's biggest gas field, which Qatar shares with Iran. QatarEnergy earlier this year signed five deals for North Field East, the first and larger of the two-phase North Field expansion plan that will ramp up Qatar's liquefaction capacity to 126 million tonnes per year by 2027 from 77 million. It later signed contracts with three equity partners to develop North Field South, the second phase of the expansion. Kaabi said negotiations with other LNG buyers in China and Europe are ongoing. LNG sold under the deal with Sinopec will be priced against crude oil.

Europe's reluctance for long-term LNG contracts could be a problem

(Bloomberg opinion column; Nov. 17) - Buyers and sellers in the liquefied natural gas market these days face a dilemma. The overwhelming marginal buyers — Europeans seeking to replace Russian pipeline gas — are looking for supply at the sort of affordable prices below $10 per million Btu that you'd get as a foundation customer of a new gas export project. Suppliers are happy to sign up new customers at reasonable prices — but only if they commit to still buy cargoes 15 years from now.

The two positions are hard to reconcile. Europeans are desperate for gas right now but see very little need for it by the 2030s. Some 63% of respondents in the region expect demand to increase until 2025, according to a survey this week by McKinsey & Co. Not a single one thinks consumption will continue rising past that date. Only a minority of respondents expect demand to increase after 2025. That's in line with the International Energy Agency's view that the turmoil from Russia's invasion of Ukraine will see gas demand peak this decade at about 5% above current levels.

There's a troubling side effect to that waning demand picture. The price of contracted LNG is roughly proportional to how long an export project gets to recoup its investment costs. With a 20-year time frame, that comes to a weighted average of about $7.50 per million Btu, the IEA wrote in its World Energy Outlook last month. Shorten it to 10 years, and the price needs to go up 20% to $9. At that price, hydrogen may be an option. Gas producers already face a shaky long-term market. If they can't sign up buyers well into the 2030s, their costs rise further — and their competitiveness falls.

Recovery of French nuclear output could help ease gas shortage

(Reuters columnist; Nov. 17) - Plunging nuclear power output has forced France to boost liquefied natural gas imports by more than any other major buyer so far in 2022, amplifying the gas market fallout from the Russia-Ukraine war and helping drive global gas prices to record highs. But a slow recovery is now underway in France's nuclear power output. Though still well below capacity, it is helping to potentially reduce France's need for gas in 2023.

In turn, lower LNG demand from France over the winter could help ease the strain on Europe's power markets, which have struggled with acute gas shortages since Russia's invasion of Ukraine in February triggered deepening cuts to pipeline flows from Russia, formerly Europe's top fossil fuel supplier. A steady restoration of low-emitting French nuclear power could also serve as a reminder to the rest of Europe of the merits of a diverse energy supply that is less reliant on imports of fossil fuels.

France normally relies on nuclear power for 70% of its electricity. But reactor shutdowns due to maintenance work, labor disputes and reduced availability of cooling water during a summer heat wave forced Europe's third-largest economy to boost LNG imports. For the 10 months to October, they were up a whopping 85% from a year before, according to data from Kpler. France's purchases of 1.6 trillion cubic feet of gas during the first 10 months of 2022 were nearly double the country's average since 2018

Germany plans for six LNG import terminals in operation in 2023

(S&P Global; Nov. 17) – The timely start-up of operations at three new German LNG import terminals will be key to boosting the country's gas supply security this winter as Berlin looks ahead to a permanent future without Russian gas. Preparations are on track for three floating storage and regasification units to be ready to begin operations by the turn of the year, and their prompt commissioning is expected to provide additional capacity for any winter wave of LNG deliveries into Europe.

In all, six FSRU projects are underway in Germany — five backed by the German government alongside one privately backed facility. Three terminals — at Wilhelmshaven, Brunsbuttel and Lubmin — are scheduled to be ready to begin operations by the end of the year, with the others expected online by end-2023. Ultimately, the first three FSRUs will give Germany almost 700 billion cubic feet per year of LNG import capacity — equivalent to around 43% of Russian imports in 2021.

However, initially the terminals will operate at a lower capacity as they ramp up. According to S&P Global analysts, Germany is expected to import around half the full capacity during calendar year 2023, with the range stemming from how much might go into Germany versus other northwest European terminals.

BP boss calls for stronger effort to reduce methane emissions

(Australian Broadcasting Corp.; Nov. 18) - The head of one of the world's biggest oil and gas producers has called for a clampdown by the industry on fugitive emissions, saying it makes no sense for companies to allow their product to escape. Bernard Looney, the boss of BP, said methane leakage from gas wells in Australia and across the globe is a "huge issue" that needs to be fixed on economic and environmental grounds.

In a wide-ranging interview, Looney also said there is a need to invest in new oil and gas projects out to 2050, even as global economies moved toward carbon neutrality. He said the unprecedented energy crisis that played out in 2022 showed how high the stakes are and why governments and investors need to be careful about how they manage the switch to renewable sources.

"What you will see over time is reducing demand for hydrocarbons, reducing investment in hydrocarbons," Looney said. "But that is not the same as no investment. Oil and gas fields decline faster than what societal demand decline will be. And in that middle, you have to invest — otherwise, you end up with the problem we have today, which is you don't have enough supply, prices go through the roof and the consumer is affected and obviously starts to question, 'What are we trying to do here?'"

Looney also noted that methane is natural gas and therefore it makes no environmental or economic sense to waste it. "The less you leak, the more you sell, and there's an economic benefit to that in itself," he said. "It's an absolute priority for our company."

Report says hydrogen 'must play key role' to meet net-zero emissions

(CNBC; Nov. 17) - Hydrogen use by the G-7 countries could jump by four to seven times by the middle of this century compared to 2020 in order to "satisfy the needs of a net-zero emissions system," according to a new report from the International Renewable Energy Agency. In a foreword to the report, IRENA Director-General Francesco La Camera said it had "become clear that hydrogen must play a key role in the energy transition if the world is to meet the target of the Paris Agreement."

Despite this assertion, IRENA's analysis — which was published on Nov. 16, during the COP27 climate change summit in Egypt — paints a complex overall picture that will require a delicate balancing act going forward. Among other things, it noted that "despite hydrogen's great potential, it must be kept in mind that its production, transport and conversion require energy, as well as significant investment. … Indiscriminate use of hydrogen could therefore slow down the energy transition."

The first of these priorities, IRENA said, related to the decarbonization of "existing hydrogen applications." The second centered around using hydrogen in "hard-to-abate applications" like aviation, steel, shipping and chemicals. Hydrogen can be produced in a number of ways. One method uses an electric current to split water into oxygen and hydrogen. If the electricity used comes from a renewable source such as wind or solar, then some call it "green" or "renewable" hydrogen. Today, the vast majority of hydrogen generation is based on fossil fuels, which is called gray or blue hydrogen.

Report finds green hydrogen consumes less water than coal plant

(The Salt Lake Tribune; Nov. 18) - In the arid West, does it make sense to create a fuel from water? That is the question behind the Utah Legislature's request for a study of the water required to produce electricity from hydrogen, fossil fuels or renewable sources like wind and solar. The Intermountain Power Agency's long-term plan is to convert its coal-fired power plant near Delta to run on "green" hydrogen produced from renewable sources. To create the hydrogen, they would use electricity to split water molecules.

The University of Utah's Energy and Geoscience Institute presented its preliminary findings to the Legislature this week. The researchers presented figures that largely confirmed what IPA has been saying: Converting to hydrogen will save considerable water versus the coal plant. The group plans to present a final report in February.

The study found that it will take 369 gallons of water to produce one megawatt-hour of electricity from hydrogen. That includes 123 gallons of water separated into hydrogen and oxygen by electrolysis. The rest of the water largely goes to driving steam turbines and cooling the hydrogen-fueled power plant much like coal and natural gas plants are operated. "Cooling is a very common way of loss," said Julia K. Sieving, a research associate in the Chemical Engineering department and one of the report's authors.

By comparison, a megawatt-hour produced from coal requires 587 gallons of water. That extra water is used to control emissions and to manage coal ash and other wastes. The study also looked at the water required for natural gas, solar and wind generation. Gas needs 219 gallons per megawatt-hour. Wind and solar had minimal requirements.

Maybe the U.S. and Saudis are not that far apart on oil price

(Bloomberg columnist; Nov. 17) - The relationship between Washington and Riyadh has reached that stage where Saudi Arabian officials give TV interviews to say how good it is. Regardless, the immediate problem between the two countries concerns — what else? — oil, where the U.S. and Saudi Arabia have been pulling in opposite directions. President Biden has released about 165 million barrels from reserves since March to ease prices. Meanwhile, Saudi Arabia has sought to support prices by curbing supply.

Beneath these cross-purposes, however, may be a sliver of common ground. A month ago, the White House announced a plan to refill the Strategic Petroleum Reserve when oil prices fell to between $67 and $72 a barrel. By establishing a guaranteed price, the idea is that it would encourage domestic producers to drill for more oil. Meanwhile, with its cut to supply, OPEC+ also sought to establish a floor under a price that had dropped from more than $120 in June to around $85 this fall.

That points to a floor of about $70 for the U.S. and a floor of about $85 for Saudi Arabia. The $15 difference looks like a decently narrow gap to bridge. In addition, the U.S. emerging as an active manager in the oil market would mark a sea change. Besides, an oil market put that's backed by SPR purchases could help U.S. producers — and, more importantly, investors — over the hump of recommitting to drilling in an uncertain world.

Longer voyages for Russian crude drive up profits for tanker owners

(Bloomberg; Nov. 20) - Oil tanker tycoons are enjoying a surge in revenue as the sanctions triggered by Russia's war are redrawing the global trade in crude. And it's set to last. The disruption is fairly simple. Europe, for decades the top buyer of Russian oil, is banning purchases from Moscow next month and has already been cutting back. Those cargoes are instead flowing out to Asia. The result is ships sailing thousands of miles farther, driving up a vital aspect of demand for tankers.

"I can't say that I have seen a trade disruption before on the scale we have now," said Halvor Ellefsen, a supertanker broker at Fearnley Shipbrokers UK. "This time, I think it's a paradigm shift, whereas previous geopolitical events have tended to be short-lived and back to normal more quickly." A key industry gauge, ton miles, which is the volume of cargo transported, multiplied by the distance it sails, is expected to increase 4.3% this year, according to Clarkson Research Services, a unit of the world's largest shipbroker.

Daily earnings for the industry’s largest supertankers reached $99,628 on Nov. 18, four times the average of the past four years, on the market’s benchmark route. The freight market will remain strong for 2023 and 2024, mainly due to “structural” changes to trade flows, said Frederik Ness, an analyst at SEB. Cargoes that were routinely being transported across the Baltic Sea to reach the North Sea port of Rotterdam are now sailing to India and China, comfortably twice or three times the distance.

U.S. heating oil costs up 65% in October from a year ago

(Reuters; Nov. 17) - Heating oil costs for U.S. households rose by 65% in October compared to the same month last year, due to depleted stocks exacerbated by low imports and production constraints, the U.S. Energy Information Administration said on Nov. 17. The EIA's weekly Heating Oil and Propane Update showed heating oil prices climbed to a record high of $5.90 per gallon in the week ending Nov. 7, according to the data for the winter heating season from October through March going back to 1990.

Households that rely on heating oil are concentrated in New England, where 33% of homes are primarily heated by the fuel, compared to the nationwide average of 4.1%, the EIA said, citing 2021 data. Stockpiles of distillate fuel in the U.S. Northeast stood at 15.2 million barrels on Nov. 11, 44% lower than for the same week in 2021, the EIA's Weekly Petroleum Status Report showed.

The East Coast also imported 38% lesser distillate fuel in the first eight months of 2022 from the same period last year, while the region's refining capacity has taken a hit in recent years, the EIA said. In 2019, Philadelphia Energy Solutions permanently idled its 335,000 barrel-per-day refinery, the East Coast's largest, after a massive fire, squeezing supplies in the country's busiest, most densely populated corridor.

Further delay looks likely for restart at Freeport LNG in Texas

(Reuters; Nov. 16) - A few liquefied natural gas vessels have turned away from Freeport LNG's export plant in Texas in recent days on expectations that the plant's restart will be delayed until December or later, according to ship tracking data from Refinitiv. The Freeport shutdown has added to the squeeze on global gas over the summer caused by Russia's invasion of Ukraine. It boosted prices in Europe and Asia to record highs, while capping gains in U.S. gas futures by leaving more fuel at home for domestic use.

Three different vessels have turned away from the plant in recent days as the facility is still not ready to be restarted. Until late last week, Freeport had said repeatedly that the plant, which can ship 2.1 billion cubic feet per day, was still on track to return to service in November after a fire in Ju e. On Nov. 18, Freeport LNG Development said it is aiming to restart its facility in mid-December, spending the rest of the month finishing reconstruction work and fulfilling regulatory requirements.

As of early Nov. 16, sources familiar with Freeport's filing said the company had not yet submitted a request to resume service to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration. Many analysts believe that means the plant will not resume operations until December at the earliest. The Freeport shutdown has already forced the plant's customers to buy expensive LNG from other sources to supply their own customers.

Environmental groups sue for review of Louisiana LNG project

(Reuters; Nov. 16) - Three environmental groups have sued the Louisiana Department of Natural Resources for exempting Venture Global LNG from needing an environmental permit to build its liquefied natural gas terminal, the organizations said on Nov. 16. The Deep South Center for Environmental Justice, Sierra Club and Healthy Gulf filed a petition last week in state court for review against the department after the regulators decided to exempt Venture Global from obtaining a coastal-use permit for development of its LNG facility in Plaquemines, 35 miles south of New Orleans.

The groups say the plant's construction will destroy nearly 400 acres of wetlands that serve as a storm buffer for nearby communities. Without sufficient protections, a hurricane would release pollution into homes, businesses, farm land and coastal water, subjecting predominantly Black and indigenous communities to risks, they said.

The Venture Global terminal is one of four under construction in the U.S. LNG backers say the gas can replace coal, a fuel that releases more greenhouse gases when burned and gives consumers an alternative to Russian gas. Opponents say LNG facilities, drilling operations and transportation can leak methane, a powerful greenhouse gas.

FERC approves another LNG export project on Louisiana coast

(Reuters; Nov. 17) - U.S. energy regulators unanimously approved the Commonwealth LNG export terminal on the Louisiana coast on Nov. 17, though Democratic members listed concerns about its impact on greenhouse gas emissions and communities exposed to pollution. The project, planned to export 8.4 million tonnes a year of liquefied natural gas, was the first to be approved by the Federal Energy Regulatory Commission in more than two years. Subject to a final investment decision, it is expected to begin shipping LNG in 2027, and could become the 10th such export facility in the country.

FERC Chairman Rich Glick said federal law covering LNG terminals requires the panel to approve the facilities unless they are contrary to public interests. Glick, a Democrat, said he was concerned that the terminal will produce the equivalent of 3.5 million tonnes of carbon emissions per year. "I still am at a loss as to why we don't at least assess the significance of the greenhouse gas emissions in terms of making our determination ... and I think it is something we need to grapple with as we move forward," he said.

The other two Democratic commissioners also voted for the $4 billion project but expressed concerns about its pollution impact on minority communities near the facility. Environmentalists warned the rush to export gas can raise prices for domestic consumers. "FERC's decision is not in the public interest for people who use gas to heat their homes, and will only further pollute environmental justice communities on the Gulf Coast overburdened by pollution that harms their environment and makes them sick," said Cathy Collentine, director of the Sierra Club's Beyond Dirty Fuels campaign.

FERC approves another extension for Gulf Coast LNG developer

(Reuters; Nov. 18) - U.S. energy regulators on Nov. 18 extended until September 2023 the amount of time liquefied natural gas developer Delfin LNG has to put the onshore part of its proposed Gulf of Mexico floating export project off Louisiana into service. The Federal Energy Regulatory Commission said in its order that Delfin sought the extension in July. Delfin is one of several North American LNG export developers that have delayed construction in recent years in part because of the inability to sign up enough long-term deals needed to finance the multibillion-dollar facilities.

There are about a dozen companies hoping to make final investment decisions over the next year to build their plants in the United States, Canada or Mexico. Many of those projects, like Delfin, have been delayed for years. In September 2017, FERC authorized Delfin to put its project into service by September 2019. Since then, FERC has granted several one-year extensions to complete the project. Delfin's project would use existing offshore pipelines to supply gas to up to four vessels that could each produce about 3.5 million tonnes per year of LNG. The company has said each vessel would cost about $2 billion, with the first expected to enter service around 2026, four years after the FID.

Floating LNG gains traction as faster alternative to onshore plants

(Bloomberg; Nov. 20) - As Europe scrambles to replace Russian natural gas with supplies from across the globe, producers are turning to a new technology to drill quickly and cheaply: small floating plants out at sea, often made out of old tankers. While liquefied natural gas is conventionally produced at large plants on the coast, connected by pipelines to production fields, companies are streamlining the process by using specialized ships and platforms that can produce the super-chilled fuel at sea.

A floating plant started producing in Mozambique last weekend, while another one may open in the U.S. next year, showing that these projects may finally be getting financing. Their rising popularity comes amid Europe's efforts to find fast alternatives to Russian pipeline gas. In so-called "floating liquefaction," the fuel is typically produced on a newly built vessel or a converted LNG tanker. Sitting above gas fields, the projects pull out the fuel from the ocean bed via risers and the gas is processed on board. LNG is stored in tanks in the hull before carriers arrive to pick up the fuel and deliver it to global buyers.

The trend coincides with a parallel interest in floating terminals to receive LNG, which Europe is also quickly setting up. The technology for making the fuel at sea has evolved over the past five years, but lower market prices have put off numerous projects before this year's demand craze for gas and higher prices. "The reputation of floating LNG is definitely improving," said Fraser Carson, an analyst at research firm Wood Mackenzie. "We are seeing lenders much more willing to provide financing for FLNG projects."

Saudi-owned South Korea refiner plans $7 billion petrochemical plant

(The Korea Herald; Nov. 17) - South Korean oil refiner S-Oil, owned by Saudi Arabia's Aramco, on Nov. 17 confirmed its $7 billion project to build a large-scale petrochemical plant in the nation's southeastern city of Ulsan. The project is the largest investment made in Korea by Aramco, which holds a controlling 63.4% stake in the refiner. The project involves building the world's largest refinery-integrated petrochemical steam crackers to produce up to 3.2 million tons of petrochemicals annually.

Utilizing Aramco's cutting-edge thermal crude-to-chemicals technology on the steam cracker will allow the oil refiner to produce high-quality petrochemicals as feedstock for plastics and other synthetic materials, according to the company. The TC2C process involves using low-quality heavy oil which is processed in the existing refinery to make feedstock for steam crackers such as naphtha and off-gas.

This is the first time Aramco's TC2C technology has been commercialized, with the hope of giving the new project a competitive edge when compared to older-generation crackers. The steam cracker treats these byproducts from crude processing to produce ethylene, propylene, butadiene and benzene. The plant will also produce polyethylene used as feedstock for making plastics and other synthetic materials.