Oil and Gas News Briefs
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This could be first year since 1998 with no LNG project approvals

(Reuters; Sept. 8) - No new liquefied natural gas export projects could be approved this year for the first time in at least two decades, banking and industry sources said, after the COVID-19 pandemic drove down energy demand and knocked prices to all-time lows. In a stark contrast to last year's record level of approvals for LNG production plants worldwide, 2020's dramatic oil and gas price drop has forced companies to delay decisions on new projects and write down their investments in existing plants.

The last year in which no new LNG exports plants were approved anywhere in the world was 1998, consultancy Wood Mackenzie said. Five investment banking and energy analysts said they expect no final investment decisions this year, while four other sources said they expect at most one or two. Before the coronavirus pandemic, the volume of new export capacity sanctioned in 2020 was expected to be similar to last year's record of more than 70 million tonnes of new annual production.

"We do not expect any major FIDs on LNG export projects this year," Morgan Stanley's lead commodity strategist for natural gas and power Devin McDermott said. "With coronavirus reducing oil demand and prices, majors' capital spending dropped, weighing on their investment and pushing out FIDs."

Giovanni Bruni and Alessandro Agosta, partners at McKinsey, said they expect all pre-FID projects to be delayed by one to two years due to CAPEX cuts and deferrals, plus difficulty in securing buyers. Most industry sources and analysts said the only project with a chance of receiving an FID this year is the Costa Azul export plant in Mexico, developed by U.S.-based Sempra Energy. In the U.S., there may be no room for new LNG projects until the middle of the decade after record capacity was added last year.

Economics changed for Australia's $200 billion LNG investment

(Bloomberg; Sept. 6) - Cooks on strike and cracked equipment are among the latest maladies to undermine Australia's $200 billion push to become the world's biggest liquefied natural gas exporter. More than a year after the completion of a decade-long LNG construction boom, two of the seven marquee projects haven't been able to work right, the nation's East Coast urban centers face an impending gas shortage blamed partly on exports, and the government is earning rather meager taxes from gas sales.

The setbacks are heating up a public debate between the pro-fossil fuel government and environmentalists over the role of gas in the country's future. Meanwhile, the pandemic has cast doubt on long-term projections for the fuel and is causing billions in write-downs on gas assets. "The economics of gas have really turned upside down in short order to make some of those massive investments from 10 years ago already look like pretty poor decisions," said Ebony Bennett, deputy director at the Australia Institute.

Prelude, floating 295 miles off the coast, hasn't shipped a cargo since January due to technical glitches. Adding to its problems, a labor dispute has seen service providers, including catering, take strike action in recent weeks. Gorgon, on Western Australia's Barrow Island, is the most expensive LNG project in history at A$54 billion. Yet Chevron now needs a staggered shutdown of all three production trains at the plant after damage was found in propane kettles that are key components in the liquefaction process.

An overbuild of LNG capacity on the East Coast is often blamed for lifting domestic gas prices with Australian manufacturers forced to compete for gas with big export projects.

Exxon undertakes worldwide review to cut expenses

(Reuters; Sept. 7) - Ill-timed bets on rising demand have ExxonMobil facing a shortfall of about $48 billion through 2021, according to a Reuters tally and Wall Street estimates, a situation that will require the top U.S. oil company to make deep cuts to its staff and projects. Wall Street investors are even starting to worry about the company's once-sacrosanct dividend. Exxon weathered a series of setbacks last decade and sought to return to past prominence by big bets on U.S. shale oil, pipelines, and global refining and plastics. It also bet big on offshore Guyana, where it found up to 8 billion barrels of oil.

But Exxon's ability to finance that global expansion is no longer assured. This year the company borrowed $23 billion to pay its bills, nearly doubling its debt. In July, it posted its first back-to-back quarterly losses ever. It faces a full-year $1.86 billion loss, according to Refinitiv, excluding asset sales or write-downs. The looming shortfall of $48 billion through 2021 was calculated using cash from operations, commitments to shareholder payouts and costs for the massive expansion program Exxon had planned.

Now the company is embarking on a worldwide review of where it can cut expenses. This year's sharp drop in oil demand and pricing has shredded the plan to spend at least $30 billion a year through 2025 to revive production and earnings by expanding in oil processing, chemicals, and production, and by taking a commanding role in U.S. shale and liquefied natural gas, markets that had looked promising. Instead, Exxon must prepare Exxon to operate in a world of weaker demand for its oil, gas and plastics.

Exxon's cash from operations — estimated at $17.4 billion this year — is $20 billion below the funds needed for this year's already pared investment plan and shareholder dividend, a Reuters analysis showed.

Bank of America predicts 'terminal decline' in oil demand after 2030

(Houston Chronicle; Sept. 9) - Global oil demand, struggling to recover from the coronavirus pandemic, could peak during this decade as electric vehicles become more widespread, according to a new report. Demand for crude worldwide plunged by 16 million barrels per day during the second quarter, the largest drop in a single quarter, according to a Bank of America Securities report released this month. Although demand is recovering as countries lift travel restrictions, Bank of America analysts forecast oil demand could take three years to recover from the pandemic before peaking in 2030.

"Oil demand grows on our estimates to 2030, a point at which we see oil demand peak and go into terminal decline," said Francisco Blanch, a commodity and derivative strategist with Bank of America Securities. "The peak is caused by the erosion of demand growth from substitution into electric vehicles."

Bank of America expects electric vehicles will make up a third of sales of lighter vehicles by 2030, and 95% of sales by 2050. That means oil demand could peak at around 105 million barrels per day by 2030 and decline to 95 million barrels per day by 2050. If trucks also become electrified during this decade, global oil demand could fall to 76 million barrels per day by 2050, the bank said.

Oil field services provider Baker Hughes moves to low-carbon future

(Reuters; Sept. 8) - Baker Hughes is pivoting to customers preparing for the transition to a low-carbon future, bolstering its footprint beyond oil and gas oil field services, its chief executive said Sept. 8. The company will continue to downsize its oil field services and equipment portfolio, CEO Lorenzo Simonelli said at the Barclays CEO Energy-Power conference, putting more emphasis on the energy transition and technology needed for renewables. It has already been shedding some oil field assets.

The shift comes as more customers commit to lower-carbon operations, and as growth in renewable energy such as wind and solar are accelerating. Baker Hughes has said it is targeting net-zero carbon emissions by 2050. Baker Hughes is adjusting to a sharp drop in oil demand as the pandemic and a short-lived price war drove its big customers to idle equipment, slow new oil and liquefied natural gas projects, and cut employees.

“We believe that the changes facing the oil and gas markets and rapid growth in demand for lower-carbon solutions warrant an acceleration of our strategy,” Simonelli said in remarks to the virtual conference. Baker Hughes sees opportunities as more companies move to reduce their carbon footprints, including by upgrading gas turbines to reduce carbon emissions and buying methane monitoring products. It’s also scaling up remote monitoring gear. Longer-term it sees opportunities in carbon capture.

Utilities see future in carbon-free ‘green hydrogen’

(The Wall Street Journal; Sept. 5) - U.S. utilities are increasingly exploring the use of what is called green hydrogen made from wind and solar energy to reduce emissions from power plants and pipelines. The early investments are expected to help commercialize a costly technology that has been slow to develop despite its ability to provide a steady source of carbon-free power. Utilities and policy makers are beginning to view the technology as necessary to support ambitious renewable-energy goals.

The Los Angeles Department of Water and Power is leading a $1.9 billion effort to convert a coal-fired power plant in Utah to run on gas and hydrogen produced with excess wind and solar power. The plant has long been one of Southern California’s most significant power sources. The gas turbines, slated for completion in 2025, will initially burn a 30% hydrogen fuel mix. Within 20 years they are expected to run entirely on hydrogen to comply with a California law that requires carbon-free power by 2045.

Hydrogen is most often produced from coal or gas through carbon-emitting processes. The production of green hydrogen eliminates those emissions by using renewable energy to strip hydrogen atoms from water molecules through a process called electrolysis. Currently, only 1% of the hydrogen produced is green hydrogen.

“From a cost perspective, it doesn’t compete with natural gas at this point,” said the water department’s director of external energy resources. But the conversion a long-term investment in changes that lawmakers and regulators are requiring. And the price of green hydrogen is expected to become more competitive in the coming years.

PetroChina’s emissions target unexpected; maybe not what it seems

(Bloomberg commentary; Sept. 5) - There’s one surprise entrant in the group of oil companies announcing plans this year for how they’ll reduce emissions: PetroChina. China’s oil companies, unlike their peers in the U.S. and particularly Europe, don’t traditionally treat climate targets as a major issue. So PetroChina’s announcement last week that it would seek a “near-zero” target for emissions by 2050 was unexpected.

Though it could be taken as a sign of change in Beijing, it's probably best not to get too excited. In most countries, the chief objective is to minimize reliance on coal, the worst-polluting of fossil fuels. In China, however, bureaucrats are more preoccupied with self-sufficiency, so limiting oil imports is a bigger concern. PetroChina's news may just be confirmation that it is national security, rather than climate, that's driving energy policy.

Output from its domestic oil wells has been more or less flat for four years. Despite domestic demand increasing by about a third between 2015 and 2019, oil production from local wells fell 11%. As a result, the country went from importing 31% of its crude in 2002 to 72% last year, at a cost of some $220 billion. There's no shortage of policy ambition to reduce this dependence on oil imports. But coal is a very different picture.

Thanks to vast domestic reserves and demand that's down 9.2% since 2013, China has consistently been able to source around 95% of its coal domestically. Just last year it completed an 1,127-mile railway to shift soot south from its mining regions north and west of Beijing toward customers farther south, which have traditionally been dependent on imports. But further reliance on coal would be a tragic mistake. If China is worried about energy security, there's no type of power less import-dependent than renewables.

Saudi Arabia's need for cash pressures Aramco to pay dividend

(Bloomberg; Sept. 9) - The world's biggest oil company is getting squeezed by its main shareholder, the Saudi Arabian government. Even with crude dropping to $40 a barrel this week and its cash flow plunging, Saudi Aramco is trying to pay a $75 billion dividend this year, almost all of it to the state. Concerns are mounting among many, including global fund managers who bought shares during an initial public offering last December, that Aramco is putting strategic projects on ice and racking up debt too quickly.

Aramco has been the country's cash cow for decades. But the pressure it faces has been thrown into sharper relief by the coronavirus-induced collapse in energy demand. Crown Prince Mohammed bin Salman, the 35-year-old de facto ruler, has pledged to diversify the kingdom from oil and spend billions developing everything from futuristic cities to tourism and financial services. For that, he needs Aramco's money.

"The crown prince has basically decided the company is a piggy bank he can raid to fund his other projects," said Jean-Francois Seznec, a senior fellow at the Atlantic Council of Washington's Global Energy Center. The crown prince's desire to get money out of Aramco may only increase. Since Chairman Yasir Al-Rumayyan said earlier this year that he wanted to sell some assets, the economy has worsened. The government has been forced to raise taxes and reduce public workers' allowances.

Natural gas may be losing ground to renewable energy

(Bloomberg; Sept. 9) - Even the cleanest fossil fuel is losing its appeal to rich nations. Just a few years ago, gas was hailed as vital for the transition toward an economy that runs on renewable energy. But sentiment is changing and the fuel is going the same way as coal, its dirtier sibling shunned by governments, utilities and investors. The cancellation of the giant Atlantic Coast gas pipeline in the U.S. and Ireland's decision to drop its support for a liquefied natural gas import terminal this summer are the latest signs that gas is falling out of favor with everyone from regulators to asset managers.

As countries intensify efforts to meet climate obligations, the fuel used for heating, cooking, and power production is poised to lose out to solar, wind, and private and public energy efficiency measures. While natural gas only emits about half the carbon dioxide of coal, flaring and methane leaks have tarnished its reputation across the globe, according to Nick Stansbury, head of commodity research at Legal & General Investment Management in London. Many investors are also shying away to instead allocate funds to projects aligned with objectives of the Paris Agreement, he said.

"Gas companies have underestimated that the public opinion is changing rapidly," said Stansbury. "Coronavirus lockdowns have had a role in that change, as investors are also stepping back and rethinking how things should be done." More than 1,200 institutions managing over $14 trillion in assets have committed to divest from fossil fuels, up from 181 managing $50 billion five years ago, according to a report from Fossil Free, an international environmental movement.

Coal gets a brief reprieve from losing market share to gas

(The Wall Street Journal; Sept. 6) - Coal is on its way out of the electrical grid, but not without some dying flickers. Cheap, cleaner natural gas had been eating away at coal's market share for some time. But with gas prices edging toward $2.50 per million Btu, nearly 70% higher than the lowest point this year, the tables are about to be turned.

Natural gas prices are being propped up by stronger-than-expected power demand — lots of air conditioners running in homes helped offset losses in commercial usage — as well as muted supply. Energy companies halting production from oil wells due to low oil prices have shut off associated gas in the process. As a result, the U.S. Energy Information Administration estimates that coal's share of electricity generation will tick up to 22% in 2021 from 18% this year, while gas-fired power's share will decline to 35% from 40%. That comes after more than a decade over which coal gradually lost share.

RBC analyst Christopher Louney estimates that gas burn for electricity could decline 2% year over year in 2021 while coal generation picks up 6%. Yet none of this portends a lasting comeback for coal-fired power. As recently as 2015, coal was the largest fuel source for electricity in the U.S., but low gas prices and strict environmental standards have pushed many coal plants to shut down. Another 25 gigawatts, roughly 11% of coal power capacity as of year-end 2019, is expected to retire by 2025, according to the EIA.

Russian shipyard in Vladivostok will build ice-class LNG carriers

(The Barents Observer; Norway; Sept. 7) - The Zvezda yard in Vladivostok in Russia's Far East will have plenty of complex Arctic shipbuilding to do over the next several years. Not only is the yard assigned with building the new Lider-class icebreakers, a growing number of new tankers are being added to the company's order books. That includes at least 15 carriers for the Arctic LNG-2 project. Smart LNG, a joint venture of shipper Sovcomflot and gas producer Novatek, signed contracts Sept. 7 with financial institution VEB.RF and Zvezda Shipbuilding for construction and lease of 10 carriers.

Smart LNG also signed long-term charter agreements for the vessels with Arctic LNG-2, a Novatek majority-owned venture building a gas liquefaction and LNG export terminal on the Gydan Peninsula. In total, contracts for 15 LNG carriers have now been signed that cover shipbuilding, financing, leasing, and charters, Sovcomflot reported. Arctic LNG-2 is nearby to Novatek's first LNG project, Yamal, which started operations in 2017.

Arctic LNG-2 is operated by Novatek in partnership with French oil and gas major Total and Chinese and Japanese partner companies. The new LNG carriers coming from the Zvezda Shipyard will be ice-class ships, 985 feet long with capacity to carry 172,600 cubic meters of LNG, running with the equivalent of 45 megawatts of power and able to break through ice up to 6-feet thick.

31-year-old Australia LNG plant has room to handle more gas

(LNG Industry; Sept. 7) – A new report from the global energy analysts at Wood Mackenzie shows that the North West Shelf (NWS) LNG project in Australia could have up to 7 million tonnes per year of spare production capacity available by 2027. This equates to 40% of the project's nominal capacity. The Woodside-operated five-train plant has been producing LNG since 1989, with spare production capacity becoming available for the first time next year as the gas fields that feed the plant are in decline.

"Decisions on how to fill this gap need to be made now, not only because time is running out, but also because the joint venture is breaking up. Chevron is running a process to sell out of the NWS, and we see other majors likely to follow," said Wood Mackenzie senior analyst Daniel Toleman. "We see two windows of opportunity for backfill: One for smaller projects with short lead times, and the second for larger-scale resources that can extend the life of the NWS through to 2050."

While “good progress has been made on near-term backfill small-scale projects,” Toleman said, “in the longer term, large-scale developments are needed. The Scarborough and Browse developments, both operated by Woodside, are the most likely backfill options due to their size.” Browse, however, “is a remote, complex, carbon-intensive and high-CAPEX greenfield mega-project. As such, it faces a myriad of challenges in current market conditions,” Toleman said.

Qatar will face challenges in marketing expanded LNG supply

(Petroleum Economist; Sept. 8) - Qatar lifted its 12-year moratorium on further development of the vast offshore North Field in April 2017 and, three years later, is steamrolling forward with the largest liquefied natural gas production expansion the industry has ever seen. The expansion, targeting start-up in 2025, would lift Qatar’s annual LNG capacity from 77 million tonnes to 126 million tonnes.

The message is that Qatar is determined to maintain a vice grip on global LNG markets. With the lowest production costs in the world — aided by stripping valuable condensates from the North Field’s rich gas — a geographically enviable location that can serve Atlantic and Pacific markets and a stellar balance sheet, the real question is not Qatar’s ability to build this capacity, but how it will find a home for the output.

Qatar may have to accept the inevitability of greater contract flexibility for buyers than in previous agreements. And it still faces the challenge of marketing the significant boost in volume. Unlike previous expansions, Qatar is moving forward without having the capacity underpinned by new long-term contracts. Qatar will rely on yet-to-be-confirmed project partners to market or, in a best case, contract for some of this incremental output. It is likely to seek an Asian regional energy player or end-user as a cornerstone partner, a strategy that could simultaneously deepen its economic ties with China.

Producers hurry to get permits for drilling on federal land

(Reuters; Sept. 8) - Oil producers in the top U.S. shale fields are stockpiling drilling permits on federal land ahead of the U.S. presidential election, concerned that a win by Democratic candidate Joe Biden could lead to a clamp-down on oil field activity. Federal permitting in the largest U.S. oil field in the Permian Basin, in Texas and New Mexico, is up 80% in about the past three months, which analysts attribute to a hedge against a win by Biden, who currently leads President Trump by several points in national polling.

Biden’s climate plan includes banning new oil and gas permits on public lands, which industry groups say would hurt the economy and cut off an energy boom that has made the United States the world’s largest crude oil producer. The shale revolution of recent years boosted U.S. crude output to roughly 12 million barrels per day last year through hydraulic fracturing, or fracking, which is environmentally controversial as it involves pumping water, sand and chemicals into rock at high pressure to release oil or gas.

As of Aug. 24, producers have received 974 permits so far this year for new wells on federal land in the Permian, compared with 1,068 for all of last year and 265 in 2018, according to data firm Enverus. In the 90 days up to Aug. 24, producers received 404 permits in the Permian, compared with 225 and 11 in the same period in 2019 and 2018, respectively. The scramble for permits comes despite the weak outlook for oil drilling and low prices due to the ongoing coronavirus pandemic.

Colorado considers more distance between wells and homes, schools

(The Denver Post; Sept. 5) - Dueling health studies, conflicting conclusions and differing reports from people living near oil and gas wells versus reports from companies dominated a hearing Sept. 4 on new rules for how far wells should be from homes and schools. The Colorado Oil and Gas Conservation Commission heard from its staff as well as oil and gas companies, environmental organizations and people concerned about the potential health risks from drilling in populated areas.

Setbacks, the distance between wells and homes or schools, are among several issues the commission is considering as it undertakes an overhaul of the state’s oil and gas rules. The distance of setbacks is one of the most controversial aspects of an issue that has roiled communities and policy makers for the past several years — the expansion of oil and gas development in Colorado, particularly in and near neighborhoods.

Commission staff recommended 2,000-foot setbacks from child care centers or schools. For homes, the line would be 500 feet for fewer than 10 residential units or 1,500 feet from 10 or more residential buildings or multi-unit residences. In a change from current practice, the setback would be measured from the edge of the well pad rather than the well head, which might be in the center of the pad. Environmental and community groups support setbacks of at least 2,500 feet. Industry generally supports the proposed setbacks. In 2018, voters rejected an initiative to mandate 2,500-foot setbacks.

Investors sue Anadarko, alleging fraud over failed oil prospect

(Bloomberg; Sept. 9) - The meeting would mark the beginning of the end of Lea Frye’s career in oil and gas. It was February 2014. Frye, at the time a senior engineer with Anadarko Petroleum, had the job of calculating how much oil was waiting to be extracted from the company's acreage. She was forthright about her analyses. "She tells the truth no matter the circumstances," her manager said in a performance review.

Going into the conference with senior executives, Frye had concluded that Anadarko's most ballyhooed find, called Shenandoah, was "likely much smaller" than the company claimed. She told Anadarko's top brass that their excitement about the Gulf of Mexico prospect was not justified. The reaction was swift. "You do not know anything," Vice President Ernest Leyendecker told her, according to documents recently unsealed by the U.S. District Court for the Southern District of Texas. Shenandoah was "the best field ever," he said — as good as any discovery Anadarko had ever made.

Stockholders are now suing the company for fraud. The investors' complaint says the company continued to express publicly — despite worrisome drilling results — that Shenandoah was a game-changer worth as much as $4 billion. Frye left Anadarko in 2016. The next year, the company wrote off Shenandoah's entire value. The project had gone from a multibillion-dollar golden goose to worthless. Frye said she was harassed, sidelined and eventually hounded out of Anadarko, according to court documents. In their lawsuit, investors are pointing to Frye's experience as evidence that Anadarko executives kept repeating their rosy expectations long enough to profit from them.

Russia wants to regain, or even increase, its share of oil market

(CNBC; Sept. 8) - Russia and other major oil producers must regain, and even increase, their market share once demand returns, Russia's energy minister said. "When demand begins to return to pre-crisis levels, it will be extremely important for Russia, like other oil-producing countries, to regain market share as soon as possible and, possibly, even increase it," Russia's Energy Minister Alexander Novak said in an article published in the ministry's magazine on Sept. 8.

OPEC, Russia and other non-OPEC producers — known collectively as OPEC+ — are currently cutting output by 7.7 million barrels a day until December. The alliance agreed to impose the production cuts in response to lower demand due to the coronavirus pandemic and global economic downturn. From January 2021, the cuts are expected to taper further to 5.8 million barrels per day, with these expected to last until April 2022.

Russia and other major oil producers have found themselves ceding market share to U.S. shale producers in recent years with the U.S. becoming the largest oil producer in the world in 2018. Wary of the damage that lower output is doing to its own oil industry — both to producers and its oil field services sector — the Russian government is looking to support the industry and could launch a scheme (including tax incentives) to encourage companies to drill several thousand wells with the idea being that the wells are left unfinished but can quickly be put into use after the OPEC+ deal ends in 2022.

Overbudget Norwegian North Sea project still needs more work

(Reuters; Sept. 8) - Norway's Equinor must drill several new wells at its much-delayed Martin Linge oil and gas field in the North Sea in order to ensure safe operations before production starts, the company said Sept. 8. Originally set for completion in 2016 under its then-operator Total, the project was taken over by Equinor in 2018. Estimated to hold 256 million barrels of oil equivalent, the project was originally estimated at $3.3 billion. The latest forecast released by the Norwegian government in 2019 stood at $6.1 billion.

"Four gas wells that were drilled at Martin Linge before 2018 have well barrier deficiencies that are considered to make them inappropriate for safe production," Equinor said. "The wells are considered safe as they are now, but we will keep them plugged and under continuous monitoring until we have reduced the pressure in the formation by producing from other wells," the company added. Up to three new wells will be drilled at a cost of around 2 billion Norwegian crowns ($222 million), Equinor said.

Equinor has described the field's main reservoir as structurally complex, characterized by high pressure and high temperatures. The company said in May it had postponed the planned start-up to 2021 from 2020. A new update on costs and the start-up is due next month when the Norwegian government presents its fiscal budget for 2021. Equinor has operated Martin Linge since March 2018 when it bought a 51% stake from Total, raising its holding to 70%. Norwegian state-owned oil firm Petoro owns the remaining 30%.

Russia closes loophole on fuel oil export duties

(Reuters; Sept. 7) - New tax regulations on shipments sent overseas may cost Russian exporters of fuel oil as much as $1 billion a year, Reuters calculations based on customs data show. Moscow has been looking for ways to shore up state coffers, which have been hit by the coronavirus crisis, and the oil and gas industry is seen as a central source of income, generating around a third of the country's budget revenues.

The state has introduced new customs rules for the export of fuel oil, which take effect Sept. 14, to close a loophole that has previously allowed sellers to avoid hefty duties. Some exporters used the loophole to pass off fuel oil and other heavy refining products, including vacuum gasoil, for duty-free products, such as heavy oil residue.

Customs data shows that producers of heavy oil products could have earned an extra $1 billion last year by exporting more than 12 million tonnes of products using the scheme. Many refineries have enjoyed high refining margins thanks to the loophole. Reuters calculations show that at a domestic oil price of $47.5 per tonne, the export duty is likely to rise to $31 per tonne from $7 per tonne for exports of light oil products.