Oil and Gas News Briefs
Compiled by Larry Persily
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Qatar signs engineering, construction contract for LNG expansion

(Reuters; Feb. 8) - Qatar Petroleum, the world's top liquefied natural gas supplier, Feb. 8 signed a contract for the first phase of expanding its North Field gas project, which will boost the country's LNG output by more than 40% to 110 million tonnes per year by 2026. The $13 billion contract — which covers major onshore engineering, procurement and construction — was signed with a joint venture of Japan-based Chiyoda and U.K.-based TechnipFMC and is known as North Field East. It is the largest single LNG project ever sanctioned, according to global energy consultancy Wood Mackenzie.

Production will start by the fourth quarter of 2025 and reach full capacity by late 2026 or early 2027, Qatar Petroleum CEO Saad al-Kaabi said in a virtual news conference. "The total cost of the project will be $28.7 billion, making it one of the industry's largest investments in the past few years and largest LNG capacity ever built," Kaabi said. Although QP has said it is ready to develop the North Field alone, the bidding process for international oil firms to take up to a 30% stake in the project's first phase will start next week, said Kaabi, who is also Qatar's energy minister.

He said he expects a decision to finalize partnerships for the field's expansion by the end of this year. ExxonMobil, Shell, Total, and ConocoPhillips are long-standing partners in Qatar's existing fleet of LNG plants. The expansion's second phase, known as the North Field South project, will lift Qatar's annual LNG production capacity to 126 million tonnes by 2027. Kaabi said QP is currently evaluating a further increase in LNG capacity beyond the 126 million tonnes. "I would say stay tuned," he added.

Qatar's LNG expansion could pressure higher-cost U.S. producers

(Houston Chronicle; Feb. 10) - Qatar Petroleum's plans for an almost $29 billion expansion of its liquefied natural gas production capacity — a more than 40% gain to 110 million tonnes per year — ramps up pressure on U.S. producers, which have been building a slew of LNG projects along the Gulf Coast to meet the world's growing demand for gas. "Qatar is pursuing market share," said Giles Farrer, Wood Mackenzie's research director. "This final investment decision is likely to put pressure on other pre-FID LNG suppliers, who may find Qatar has secured a foothold in new markets."

Several LNG projects are under construction along the Gulf Coast and four already are in operation. The export terminals have opened a new market for the large volumes of gas being produced as a byproduct of shale oil production in the Permian Basin that stretches across West Texas and southeastern New Mexico. Oil and gas companies are producing so much gas in Texas that some of it is being flared or burned off.

However, growth in U.S. LNG production may be stunted by Qatar, the world's lowest-cost producer. Qatar's LNG production can break even with gas delivered at just over $4 per million Btu, according to Wood Mackenzie. "It's right at the bottom of the global LNG cost curve, alongside Arctic Russian projects," Farrer said. U.S. LNG projects under construction have a break-even price in the range of $6.50 to $7.50 per million Btu if shipped to Asia, according to Rystad.

Total and Papua New Guinea sign fiscal deal for LNG project

(Reuters; Feb. 9) - The Papua New Guinea government and France's Total on Feb. 9 signed a long-awaited fiscal stability agreement for the Papua LNG project, Prime Minister James Marape said. After nearly two years of uncertainty over the fate of the liquefied natural gas project, Marape said the government would stick to the terms agreed to in April 2019. The project is planned for 5.4 million tonnes of LNG per year.

"It demonstrates Papua New Guinea's commitment to the Papua LNG Project and gives comfort and encouragement to the developers to progress the project," Marape said. Total and its partners ExxonMobil and Oil Search had planned to develop Papua LNG in tandem with an expansion of Exxon's 7-year-old LNG plant in a $13 billion overall investment adding three new production units at the existing Exxon-led plant, saving billions of dollars. The plan is to double the country's exports to 16 million tonnes a year.

However, Exxon has not agreed to terms sought by the government for the P'nyang gas development that was going to help feed its share of the expansion, so Total's Papua LNG project will go ahead with two new production units to be built at the LNG site, fed by the Elk Antelope gas fields. Papua LNG would still benefit from savings by building its units at the Exxon-operated site, which will also help limit its environmental impact.

Texas regulators defer permit requests for gas flaring

(Bloomberg; Feb. 9) - Texas energy regulators are taking an uncharacteristically critical approach toward burning off excess natural gas, a sign that growing pressure from environmentalists and investors to curb the controversial practice is paying off. The Texas Railroad Commission on Feb. 9 deferred a series of applications from oil companies. One request sought to flare more than $1 million worth of gas because it would be too expensive to build a pipeline to move the fuel to markets, a claim the agency's newest member said warranted "further investigation."

"Flaring is a necessary last resort during an upset, and we have work to do internally at the commission to ensure that we are not approving requests that go beyond that," Jim Wright, one of three Republican commissioners, said in a statement after the meeting. The commission is at the center of criticism over the shale industry's prolific flaring problem, given the panel's record of approving virtually every permit that comes to it.

In the past, commissioners have argued that more stringent regulations would discourage oil production, thereby wasting resources. But a recent report by Rystad Energy found that 40% of future flaring could be avoided at no cost to companies. "For years the commission has been acting like this isn't an issue, so it's exciting to see that they now want to end routine flaring," said Emma Pabst, with the group Environment Texas. "They're feeling the heat from investors and environmentalists."

Environmental groups push for tax on flared gas in Texas

(Austin American-Statesman; Texas; Feb. 7) - Environmental groups are pushing Texas lawmakers to impose a new 25% levy on gas that is vented or flared in oil production. Currently, such gas is exempt from state taxes normally levied on produced gas, as it is burned off and released into the atmosphere instead of being captured and brought to market. Groups such as the Environmental Defense Fund and Earthworks are hoping to curb such release of greenhouse gases by making it more expensive for producers to flare or vent gas than to invest in the infrastructure to capture, transport and sell it.

"Texas is one of the top oil and gas producing states, and as a byproduct of pulling oil out of the ground this gas comes out — the same gas we use in our homes to cook our food," said state Rep. Vikki Goodwin, an Austin Democrat who wrote a bill to tax flared or vented gas. "But for oil producers, they see it as a waste product. Rather than figuring out how to sell it or how to use it on-site, they're basically just throwing it away."

In addition to leading the U.S. in oil and gas production, Texas is a leader in gas venting and flaring, according to federal statistics. The industry and state regulators have taken steps to reduce the practice. Several oil and gas companies and trade associations formed a coalition to limit flaring and methane emissions, and state regulators have adopted rules requiring more detailed disclosures from companies seeking flaring permits. But environmental groups, concerned by the volume of pollutants released into the atmosphere, say the energy industry in Texas is not moving quickly enough.

Texas industry says it aims to end gas flaring by 2030

(Houston Chronicle; Feb. 10) - A coalition of oil and gas trade groups says it aims to end routine flaring by 2030 as the Texas Railroad Commission, which regulates oil and gas in the state, indicates it will crack down on the practice. The Texas Methane and Flaring Coalition on Feb. 10 said it will work to end the flaring of natural gas from oil wells when there is a lack of gas gathering and processing systems to take it to market. The organization said its members maintain the right to flare for safety reasons.

The oil industry has long battled the issue of flaring, the burning of excess gas produced during crude production. Flaring releases greenhouse gases such as methane, which is 84 times more capable of trapping heat than carbon dioxide. It's also a waste of resources that could yield $440 million of additional revenue by 2025 if 98% of the gas from wells were required to be captured, according to the Environmental Defense Fund.

A trillion cubic feet of natural gas in the Permian Basin of West Texas has been flared since 2013, according to the U.S. Energy Information Administration. Formed in December 2019, the statewide methane and flaring coalition has been working on improving operations and environmental practices to minimize flaring, such as using robots and drones to detect leaks. In November, state regulators required operators to provide more details and reasons for flaring in an effort to provide more transparency.

Texas acting contrary to its own energy interests, columnist says

(Houston Chronicle commentary; Feb. 8) - The race is on to see which companies and countries can produce the greenest fossil fuels, and Texas is falling behind. In Riyadh, Paris and Washington, business executives and government officials are no longer talking about whether oil, natural gas and coal cause climate change. Instead, they are talking about who produces the cleanest version of those fossil fuels.

Marketers call it "product differentiation." The company or region that can produce the cleanest dirty energy could end up the last one standing as the world adopts cleaner alternatives wherever possible. Even in a smaller market, oil and gas survivors will be profitable because there are some things clean technology cannot replace.

I first heard about green oil two years ago when Saudi Arabia officials started talking about how few greenhouse gases they emit while producing crude. A Stanford-led study found that because Saudi Aramco does not hydraulically fracture its wells and only rarely flares excess gas, Saudi oil has the least impact on the climate. Add in the world's lowest lifting costs, and Saudi oil becomes the logical choice for the European Union and others that will soon levy a carbon-intensity tariff on petroleum imports.

Gov. Greg Abbott, though, is on track to make sure Texas producers are blackballed. His latest political stunt was visiting an oil field service center to order state agencies and lawmakers to fight all efforts to reduce emissions. Thanks, governor, you pretty much guaranteed European and Asian nations will shop for their liquefied natural gas elsewhere. The state has decided to tell off Europeans rather than reduce gas flaring. If Texas wants to remain an energy exporter, it must give customers what they want.

Federal judge refuses to block oil line across Minnesota

(Twin Cities Pioneer Press; MN; Feb. 8) – A federal court on Feb. 7 denied a request to halt construction on Enbridge's Line 3 oil pipeline across northern Minnesota and upheld a key water quality permit granted to the project by the U.S. Army Corps of Engineers last year. The decision stems from a Dec. 24 lawsuit filed in U.S. District Court in Washington, D.C., by the White Earth and Red Lake nations and environmental groups Sierra Club and Honor the Earth that sought to stop construction.

The groups argued the Army Corps failed to consider environmental impacts like climate change and a potential oil spill. Judge Colleen Kollar-Kotelly wrote that the groups and bands did not meet the burden of proof for the injunction and said the harm of stopping construction, which began Dec. 1, outweighs environmental risks of the new line. "Most of the environmental effects stemming from the construction of Line 3 will not be 'permanent or irreversible, as the preliminary injunction standard requires,'" the judge wrote.

"Overall, the court finds the balance of harms and public-interest considerations to be a close call," Kollar-Kotelly wrote. Construction on the 340-mile Line 3 is expected to last six to nine months. More than 5,000 workers are on the job, Enbridge said last month. The pipeline will replace the aging Line 3 and move 760,000 barrels of oil per day from Alberta to Enbridge's terminal in Superior, Wisconsin, following a new route through northern Minnesota. The segments in Canada, North Dakota, and Wisconsin are already complete.

Rockies' gas producers keep pushing for access to overseas markets

(Denver Post; Feb. 6) - An organization formed to develop international markets for the Rockies' natural gas is forging ahead despite low prices and setbacks in building an export terminal on the Oregon coast that would connect the region to overseas buyers. The Western States and Tribal Nations Natural Gas Initiative just named its first board of directors and will soon release a report on how much greenhouse-gas emissions could be reduced if gas produced in the Rockies replaced coal-fired electricity in other countries.

Andrew Browning, Western States' president, and Duane Zavadil, a board member, acknowledge that the headwinds facing the group are strong. Gas prices remain low, and there is growing opposition to drilling from those who favor renewable energy and fear the worsening impacts of climate change. Methane, the main component of natural gas, is more than 80 times more powerful in the near term at trapping heat than carbon dioxide.

Another challenge: The embattled Jordan Cove liquified natural gas export terminal, proposed in Oregon remains in limbo after federal regulators said it can't move forward without a clean water permit from the state. The Federal Energy Regulatory Commission rejected an appeal in January from Calgary-based Pembina, which had challenged the state's denial of the permit. Building a West Coast LNG terminal is a "tricky environment," said Bernadette Johnson, vice president of strategic analytics at Enverus in Denver.

NOAA sustains state of Oregon's objection to coastal LNG project

(S&P Global Platts; Feb. 9) - Adding a new hurdle for the proposed and long-debated $10 billion Jordan Cove LNG project in Coos Bay, Oregon, and its 229-mile Pacific Connector Pipeline, the National Oceanic and Atmospheric Administration has sustained the state of Oregon's objection to the development. The state determined that the project is inconsistent with the purposes of the Coastal Zone Management Act.

NOAA found that the record was "insufficient to adequately assess the potential nature and extent of crucial adverse coastal effects likely to be caused by the project," according to a Feb. 8 decision by the Commerce Department's deputy undersecretary for operations. As a result, the agency concluded that the national interest furthered by the natural gas export project could not be balanced against its adverse coastal effects.

NOAA's decision follows a setback in January for the project when the Federal Energy Regulatory Commission found it could not approve an order that would get the project past an Oregon agency's denial of Clean Water Act certification. Calgary-based Pembina, which has been trying for years to develop the LNG project, said in December that the timing of the project was uncertain amid commercial and regulatory challenges.

Algeria in financial, political trouble as oil and gas exports plunge

(Bloomberg; Feb. 7) - Algeria's energy exports are plunging, threatening more financial suffering for the OPEC member and a potential repeat of the mass demonstrations that toppled the president two years ago. The North African nation is struggling to keep up shipments of oil and gas — the lifeblood of the economy — as years of mismanagement and a lack of investment take their toll.

The decrease is so severe that Algeria might cease to be a crude exporter within a decade, said Cherif Belmihoub, minister in charge of economic projections. "Algeria is no longer an oil country," he told state radio last month. Though crude has edged above $60 a barrel for the first time in over a year, prices are still less than half what

Algeria needs to balance its budget, according to the International Monetary Fund. Its fiscal break-even of $135 a barrel is higher than that of any other producer in the Arab world.

Its crude and LNG exports each declined about 30% in 2020, according to Bloomberg data, and the trend is continuing. Oil exports fell to 290,000 barrels a day last month, 36% less than in December and the lowest since at least 2017. The prime minister has ordered spending cuts to stabilize the country's finances, but his government is wary of cutting power and food subsidies. "Algeria has one of the largest welfare budgets per capita of its OPEC peers," said Bill Farren-Price, at energy research firm Enverus. Sustaining social spending "will be essential if mass protests are to be avoided."

Megamergers may be in the future for Big Oil

(Financial Times; London; Feb. 7) - When Exxon struck the biggest deal of a $300 billion wave of oil mergers during the brutal crude price collapse of the late-1990s, Mobil chief executive Lou Noto gave a warning to the industry. "We need to face some facts," he said as he announced his company's takeover by Exxon. "The world has changed, the easy things are behind us. The easy oil, the easy cost savings, they're done. So all of us are now looking for some way to make a jump."

The finances of the supermajors those deals created now are in tatters, just as the rise of clean energy and doubts about long-term oil demand force an existential reckoning — and the prospect of megamergers is in the cards again. "We've had two price crashes in the last five years and we've seen a lot of money leaving the sector," said Greg Aitken, head of mergers and acquisitions research at the consultancy Wood Mackenzie. "We've seen a lot of concerns about energy transition and ultimately demand destruction and a lot of uncertainty about how quickly that's going to happen."

ExxonMobil, Chevron, BP, and Shell recorded more than $50 billion in losses between them last year, as the pandemic-driven crash in oil demand crushed crude prices and forced them to slash spending. Reports last week that Exxon and Chevron discussed what would have been the biggest industrial merger in history during the depths of last year's market bust are a measure of the panic that swept through the sector. Investors say big deals would be a welcome reset for a sector that was shedding value before the crash and is now watching the investment landscape tilt toward cleaner rivals.

Chevron CEO says company will look different in 2040

(CNN: Feb. 8) - Chevron has built a $170 billion fossil-fuels empire that has made the 141-year-old company synonymous with the oil-and-gas industry. But the climate crisis is forcing oil companies large and small to rethink their once-reliable business models.

While U.S. oil companies have been far more reluctant than their European rivals to shift away from their cash cows, even Chevron CEO Michael Wirth concedes his company may look different in 2040.

“Oil and gas will still be a very big part. Will it be the biggest part? Time will tell,” Wirth said. “Twenty years forward there are things we are not doing today at any scale that no doubt we will be doing at a very large scale.” The Chevron boss pointed specifically to expansions into cleaner alternatives such as green hydrogen, renewable natural gas, and carbon capture and storage. The comments, from one of the captains of Big Oil no less, underscore the identity crisis facing the fossil-fuels industry.

Facing political and shareholder pressure, BP, Shell, and other European majors see a new energy future. They have announced plans to gradually retreat from fossil fuels, cut emissions and embrace clean energy including electric vehicle charging and renewable energy. Plenty of companies already excel at selling solar and wind power to the electric grid, but Chevron will focus instead on areas where it can have a unique advantage. “We’re not sure wind and solar are the technologies that offer that,” Wirth said.

Equinor sells off assets and will exit Bakken shale

(Reuters; Feb. 9) - Norway’s Equinor has agreed to sell its assets in the Bakken shale oil province after a decade of multibillion-dollar losses and criticism for poor investment decisions. Equinor will sell assets in North Dakota and Montana to Grayson Mill Energy, a company backed by private equity firm EnCap Investments, for about $900 million.

The Bakken was developed during the U.S. shale boom and produces more than a million barrels of oil a day, roughly half the peak reached in late 2019. The region has a high per-barrel cost of production, and investor demands for capital discipline have caused producers to throttle back output since the coronavirus pandemic erupted.

“Equinor is optimizing its oil and gas portfolio to strengthen profitability and make it more robust for the future,” CEO Anders Opedal said. “We still have a good position in the Marcellus and also in the U.S. Gulf of Mexico,” he told Reuters. “We will also focus on our operations in Brazil and Britain, and seek to improve our international business as operators or partners.” From 2007-2019, Equinor recorded an accounting loss of $21.5 billion on its U.S. activities, including $9.2 billion due to impairments of onshore shale and other assets, a company-commissioned report by accountants PwC has shown.

[Iraq expects OPEC+ will not change anything at March meeting]

(Bloomberg; Feb. 10) - Iraq said the OPEC+ oil cartel is unlikely to change its production policy at next month's meeting and repeated promises to deliver overdue output cuts, even as the Iraqi economy reels. The group of crude exporters meets on March 4 and members will probably agree to keep output steady in April, Iraq's Oil Minister Ihsan Abdul Jabbar said. The biggest change will come from Saudi Arabia, which will likely end unilateral cuts of 1 million barrels per day after March, he said.

"I think in March the agreement will be that output will remain on the same level," the minister said Feb. 10. The Organization of Petroleum Exporting Countries and partners such as Russia — an alliance known as OPEC+ — began unprecedented production curbs last May after the coronavirus pandemic battered economies and caused oil demand to collapse. Iraq has drawn fire from fellow members for breaching its quota on several occasions and failing to compensate, despite its repeated pledges to do so.

OPEC's second-largest producer after Saudi Arabia has a limit of 3.86 million barrels per day for the first three months of the year under the current agreement. Jabbar said Iraq will pump 3.6 million barrels a day this month if the semi-autonomous Kurdistan Regional Government complies with Baghdad's wishes. However, Iraq had said it would cap its daily January output at 3.6 million barrels, but pumped over 3.8 million a day.

[Canadian oil producers hit the rails, again]

(Calgary Herald columnist; Feb. 10) - As Canadian oil sands production has rebounded and even climbed above pre-pandemic levels, another area is also picking up steam: crude-by-rail shipments. Cenovus Energy reported Feb. 9 that after suspending all such shipments earlier last year — following the pandemic and an historic oil-price collapse — it was moving almost 28,000 barrels per day by train at the end of December.

The news comes after Imperial Oil said last week it has recently increased its crude-by-rail shipments into the range of 35,000 barrels per day. Federal data indicated November's rail exports for the industry soared 87% from the previous month's levels. "We brought crude-by-rail back on largely in (the fourth quarter) of last year," Cenovus CEO Alex Pourbaix said on a recent conference call. "Some element of rail movement makes sense, but I wouldn't anticipate that, unless we see (price) differentials widen significantly … it's not going to be a huge element of our business. It is a modest part."

Even a modest increase is noteworthy, reflecting another change in direction as oil sands production has recovered and pipelines are full again. It's also more confirmation new pipelines will be needed. "The bottleneck is back, for now," said Hillary Stevenson, director of oil markets for energy consultancy Wood Mackenzie. Rail shipments have whipsawed back and forth since mid-2018 when growing oil sands production and a pipeline bottleneck led to a blowout in the price differential between benchmark U.S. crude and Western Canadian oil. At one point, the discount eclipsed US$50 per barrel.

Winter price spike exposed weaknesses in Japan's power market

(Reuters; Feb. 4) - Japan's worst electricity crunch since the aftermath of the 2011 Fukushima crisis has exposed vulnerabilities in the country's recently liberalized power market, although some of the problems appear self-inflicted. Power prices in Japan hit record highs last month as a cold snap across northeast Asia prompted a scramble for supplies of liquefied natural gas, a major fuel for the country's power plants.

The crisis highlighted how many providers were unprepared for such high demand. Experts say LNG stocks were not topped up ahead of winter, and snow disabled solar power farms. The hundreds of small power companies that sprang up after the power market was liberalized to new entrants in 2016 have struggled the most, saying the government does not disclose the market data they need to operate. The companies do not have their own generators, instead buying electricity on the wholesale market.

Prices on the Japan Electric Power Exchange hit a record high of 251 yen ($2.39) per kilowatt hour in January, equating to $2,390 per megawatt hour of electricity, the highest on record anywhere in the world. One megawatt hour is roughly what an average home in the U.S. would consume over 35 days. The vast majority of the new, smaller power providers in Japan are locked into low, fixed-rate sales contracts they had set to lure customers from bigger players, crushing them financially during the January price spike.

Japan reworked its power markets after the nuclear disaster in 2011, liberalizing the sector in 2016 while pushing for more renewables. But Japan is still heavily reliant on LNG and coal, and only four of 33 nuclear reactors are operating. Utilities took extreme measures — from burning polluting fuel oil in coal plants to scavenging the dregs from empty LNG tankers — to keep the grid from breaking down during the supply squeeze.

Oil majors are winning bidders for U.K. offshore wind power leases

(Bloomberg; Feb. 7) - Oil majors are paying a hefty premium to develop the next generation of major British offshore wind farms after BP and Total won contracts in an auction, paying more than many of the utilities that have dominated the space until now. The government auctioned seabed rights that will allow about 8 gigawatts of new wind farms, enough to power more than 7 million homes. With oil majors taking a majority of the sites, it's a sign that green energy companies are facing a new era of competition for some of the world's biggest renewable energy projects.

The winning companies will pay about $1.2 billion per year in total for up to a decade to develop the wind farms. BP led the bidding with an offer about 80% higher than the average of its competitors in the auction for sites in the waters around England and Wales, an area it is long familiar with through its oil operations. “These huge upfront costs will put up barriers to entry for utilities and oil and gas companies without very deep pockets,” Barclays analysts led by Dominic Nash said in a note.

It’s the first time in a decade the government has offered seabed rights for new wind farms and the first time it’s done so with this kind of competitive auction. Winning bids came from a consortium of BP and German utility EnBW for a total capacity of 3 gigawatts, while a partnership of Total and Macquarie’s Green Investment Group got 1.5 gigawatts and RWE’s renewables arm won 3 gigawatts. Getting hold of seabed rights is the crucial first step in building a wind farm, a process that can take years.

South Korea plans world’s largest offshore wind farm

(Reuters; Feb. 5) - South Korea unveiled a 48.5 trillion won ($43.2 billion) plan to build the world's largest wind power plant by 2030 as part of its move to an environmentally friendly recovery from the COVID-19 pandemic. The project is a major component of President Moon Jae-in's Green New Deal, initiated last year to curb reliance on fossil fuels in Asia's fourth-largest economy and make South Korea carbon neutral by 2050.

Moon attended a signing ceremony in the southwestern coastal town of Sinan for the plant, which will have a maximum capacity of 8.2 gigawatts. "With this project, we are accelerating the eco-friendly energy transition and moving more vigorously toward carbon neutrality," Moon said. Utility and engineering companies will provide 47.6 trillion of the funding. The government will provide the remaining 0.9 trillion, Moon's office said.

U.S. propane prices up 70% since late November

(The Wall Street Journal; Feb. 10) - Propane prices have climbed more than 70% since late November, thanks to an explosion in patio heating and an uptick in exports to Asia. Now an arctic gust expected to deliver some of the coldest temperatures in decades to the Great Plains and upper Midwest could push prices for the rural heating fuel even higher. Futures prices at propane-trading hubs in Texas and Conway, Kansas have risen to 86 cents a gallon and 95 cents, respectively, up from about 50 cents in late November.

Prices for propane, a byproduct of gas drilling and oil refining, are up more than fourfold from the bottom in March, when lockdowns sent prices crashing and the market hadn’t yet contemplated cold-weather outdoor dining. Without much winter weather until lately, the propane market has been buoyed by overseas buyers as well as sales to stuck-at-home Americans and restaurants trying to extend patio season with portable heaters.

Orders from restaurants and resellers — such as gas stations and hardware stores that sell propane to homeowners with portable tanks — helped to counteract sluggish autumn and early winter sales to homes heated with propane, said Michael Stivala, CEO of Suburban Propane Partners. Seven winters ago during a similarly frigid spell, propane prices shot up to nearly $5 a gallon at the Conway, Kansas, hub, which serves the region where below-zero temperatures are now expected. Back then in the winter of 2013-2014, a lot of the supply was used to dry a bumper crop of corn.