

Exclusive

## The great shale shut-in is underway, but questions linger on long-term impact

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A pumpjack near Oklahoma City on April 21. Thousands of oil wells are shut in across the most prolific shale basins in the U.S., an unprecedented situation caused by the coronavirus-fueled crash in oil prices and a massive supply glut. Source: AP Photo

U.S. shale drillers needed to slash oil production fast and deep as the coronavirus pandemic vaporized demand, tanked prices and left the world awash in unwanted crude.

Natural production declines from spending cuts and canceled drilling plans were not anticipated to be enough to avoid hitting the physical limits of oil storage capacity, a potential crisis that caused benchmark crude oil futures to plunge into negative territory in April.

So oil and gas companies large and small ranked their assets, well by well, and chose which ones to keep pumping, which ones to throttle back and which ones to shut down, maybe for good. It was, for many, a brutal calculus that resulted in thousands of wells getting shuttered in the country's most prolific oil provinces, and it created a great experiment involving well operations and geology that those inside and outside the industry are watching closely.

"We just tromped on the brake pedal with both feet and slowed down production dramatically, such that it looks like we are going to get through" veteran Midland-based oilman Kyle McGraw said in an interview. "People shut in at much greater rates because of that fear, a month ago, when we had that negative \$37 oil."

Market observers now wait to see how and when those wells will come back online, after a rally in oil prices. Some producers anticipate bringing shut-in wells online again if West Texas Intermediate oil prices remain above \$30 per barrel.

As they turn the wells back on, the geology of U.S. shale may make for a smoother recovery from a technological standpoint in the U.S. than in other parts of the world, experts say. But what was dubbed "the great shale shut-in" by a prominent industry journal is also new territory that could bring with it new technical challenges and costs, creating significant uncertainty over potential impacts to shale reservoirs, those experts say.

So far, U.S. oil production has fallen to about 11.4 million barrels per day — around 1.7 million barrels below a peak in mid-March, according to the U.S. Energy Information Administration. Curtailments could rise above 2 million bbl/d in June, according to some analyst estimates.

"We haven't really gone through this experiment of shutting in wells for some period of time and then trying to reopen them," veteran petroleum geologist Scott Tinker, the director of the **Bureau of Economic Geology** at the University of Texas at Austin, said in an interview. "There are a lot of physics that we are going to learn, and economics."

### Changes in the subsurface

Physically shutting down an oil well, typically, is the easy part. The more vexing and uncertain challenge is bringing it back. "When you shut in wells, especially for a long period of time, you have a lot of surprises when

you turn them back on," Clay Bretches, an executive of operations at Apache Corp., said during a May 7 earnings call. "Some of them are good and some of them are bad."

Oilfield workers can often perform the actual shut-in remotely, although equipment usually needs to be treated with chemicals to prevent corrosion. That is a top concern among producers, but the actual process, known as "pickling" a well, is relatively inexpensive.

Once shut in, the biggest shock to the well is an abrupt change in pressure dynamics, including the oil and gas flowing into the wellbore, according to former Penn State geoscience professor Terry Engelder, known as the "father" of the Marcellus Shale for his work identifying the vast potential of the province in 2007.

"What you will find is that for the most part wells don't like being shut in for several reasons," Engelder said. In shale, one of those top reasons is that the wells run the risk of the tiny fractures made by fracking closing up again.

"It's really easy to shut a well in and open it up," David Ferris, director of the University of Oklahoma's Ronnie K. Irani Center for Energy Solutions, said in an interview. "You literally open the valve or close the valve or turn the pump on or turn the pump off. The physical act is not hard. The associated impacts of that physical act are what's challenging."

Ferris explained that the fluids and pressure in the well start to settle once the churning pumpjack that keeps an oil well flowing gets turned off. This settling alters the ratio of oil, gas and water and the amount of energy and capital required to get the well flowing again.

The reservoirs that horizontal wells target, often tight shale rock, are far less porous than conventional wells drilled down into a pocket of oil trapped in the earth. That means the changes in fluid and pressure happen much more slowly in horizontal wells, which in theory could lessen the burden that U.S. producers will face compared to rivals in other parts of the world.

Amy Myers Jaffe, director of the Council on Foreign Relations' energy security program, explained the dynamic in a recent interview with S&P Global Market Intelligence. "One of the geologically strange things about shale ... is that you can stop drilling now in the United States onshore for a year, two years, three years, and then if you change your mind because the oil is needed, and you can amass the capital and some personnel, you can drill again, and you don't ever have to worry about the so-called reservoir condition."

It is not that way in places like Venezuela and Iraq, which are dominated by more conventional plays that could require billions of dollars to restart damaged fields, Jaffe said.

Into the unknown

Roughly two decades have passed since the combined techniques of horizontal drilling and hydraulic fracturing unlocked vast reserves of oil previously considered uneconomical to extract. Never in that time has U.S. shale shut-in on the basin-wide scale for an extended period of time.

Shut-ins for days or weeks at a time is common practice in the oilfield, former Apache Corp. engineer George King, who is now a completions consultant with Viking Engineering working on shut-ins underway, said in an email. Inland producers might shut off an active well for a month to accommodate a crew fracking a new well nearby. King has worked on offshore wells that were shut-in multiple times per year for days or weeks to accommodate maintenance or repair on topside equipment or pipelines.

"[A] long term shut-in is not common, but enough has been done to at least offer some guidance," King said. "Shutting in a well is very tricky and damage by the shut-in can be severe or minor."

Factors that will determine the severity include the length of the shut-in and the conditions of the individual well, including the natural reservoir pressure.

"To shut it in, and expect 30, 60, 90 days later for it to be a similar flowback mix is pretty reasonable — It's not a big worry," said McGraw, president of Trinidad Energy, one of the basin's smaller operators, and the chairman of the Permian Basin Petroleum Association. "The general perception is, yes, you should be able to turn them off, turn them back on."

Significant shut-ins could still set the stage for violent price increases, according to Goldman Sachs and other market observers who anticipate a longer-term rise in oil prices as demand recovers. Some analysts have raised

concern that the recent oil price rally will spur producers to turn wells back online too soon, driving up excess supplies and creating more problems for the industry.

"It's going to be volatile because the market's on a hair-trigger," Bernadette Johnson, vice president of market intelligence for Enverus, said in an interview. "Nobody knows what to do because nobody knows when demand comes back."

#### Weighing what wells to shut-in

IHS Markit expected the bulk of cuts to avoid the newest, most prolific wells. Instead, it expects operators will opt for wells with established production histories. Still the research and consulting firm estimated around 1.4 million bbl/d of the about 1.75 million bbl/d that producers will curtail by early June will likely come from relatively prolific shale wells.

IHS Markit analysts predicted about 550,000 barrels per day would stay off the market long-term, or at least until WTI prices rise higher than the \$50 per barrel threshold that would likely be required to repair the impacts from shuttering them.

Through the recent earnings season, oil and gas companies have been cautious in detailing which wells they have shut in and which wells they have curtailed, a less costly means of cutting production. Most producers are shutting in the wells they believe can be brought back to life later and still be profitable, according to Karr Ingham, the executive vice president of the Texas Alliance of Energy Producers.

"They have a pretty good idea of which ones can be shut in with the possibility of bringing them back to life without difficulty or damage," Ingham said in an interview. In some cases, where producers believe that wells could not be brought back in the case of a complete shut-in, they have choked back production severely.

There are more considerations than simple petroleum engineering that go into well shut-ins, University of Oklahoma's Ferris said. Some wells are holding the lease by their production, some operators have minimum volume commitments to midstream operators and others have royalty agreements with leaseholders. If these conditions can be cleared the equation gets simpler: Is the well bringing in more cash than it takes to operate?

"If the answer is no, then you have to start asking questions," Ferris said.

#### Varying approaches

Oil and gas companies disclosed varied approaches to shut-ins in recent weeks. Pioneer Natural Resources Co. CEO Scott Sheffield said much of the 7,000 bbl/d that his company had curtailed came from "high operating cost vertical wells." Ingham speculated that Pioneer may not have shut-in those wells because of economics, but because they would be easier to restore when prices increase.

In Apache's case, CEO John Christmann told investors the company had shut in around 2,500 wells that produce a few barrels a day on average and 150 barrels of water — the kind of late-stage assets called stripper wells that IHS Markit expected to make up 350,000 bbl/d of the curtailments in the U.S.

Conversely, Exxon Mobil Corp. is targeting its newer, higher producing wells, CEO Darren Woods told investors in early May. "You're better off deferring that high production rate into a period with better pricing," Woods said, adding that depending on market conditions, "We've got the flexibility to bring a lot of those wells back on quickly and ramp up what we're doing."

The pipeline company Targa Resources Corp. told investors earlier this month that it was working to forecast when there would be shut-ins and when to expect wells to start back up but that the company expected most wells could come back online without reservoir damage.

"Could there be some older, really low rate vertical wells and some things which they shut-in and just don't bring back? I think there could be some amount of those as well," Targa CEO Matthew Meloy said during an earnings call. "But I think for the most part, we'd expect the shut-in volumes to come back and perform well when those volumes do come back."

Energy Transfer LP said it had seen around 8% of volumes shuttered in the production basin around Midland, Texas. But a quarter of that had been turned back on by May 11, Energy Transfer Chief Commercial Officer Marshall McCrea said during an earnings call. "We see that things have bottomed out, in our opinion, and that things are improving, and they're going to grow," he said.

Few people, if anyone, expect the end of the great shale shut-in to offset a dramatic decline in U.S. production this year and perhaps in the years following. Oilfield workers have been laid off en masse. More than half the country's drilling rigs have been idled. Fracking fleets are being decimated.

"As fast as we jumped on the brake, how fast will we move our foot over to the gas pedal now?" McGraw said. "Will we go to the gas pedal with both feet? I think not."

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