Is the Permian Still King of the Hill?

Crude growth rate slows compared to other basins.

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Data Sources for This Publication
U.S. Energy Information Administration
To discover more about the data sources used, click here.

West Texas Behemoth

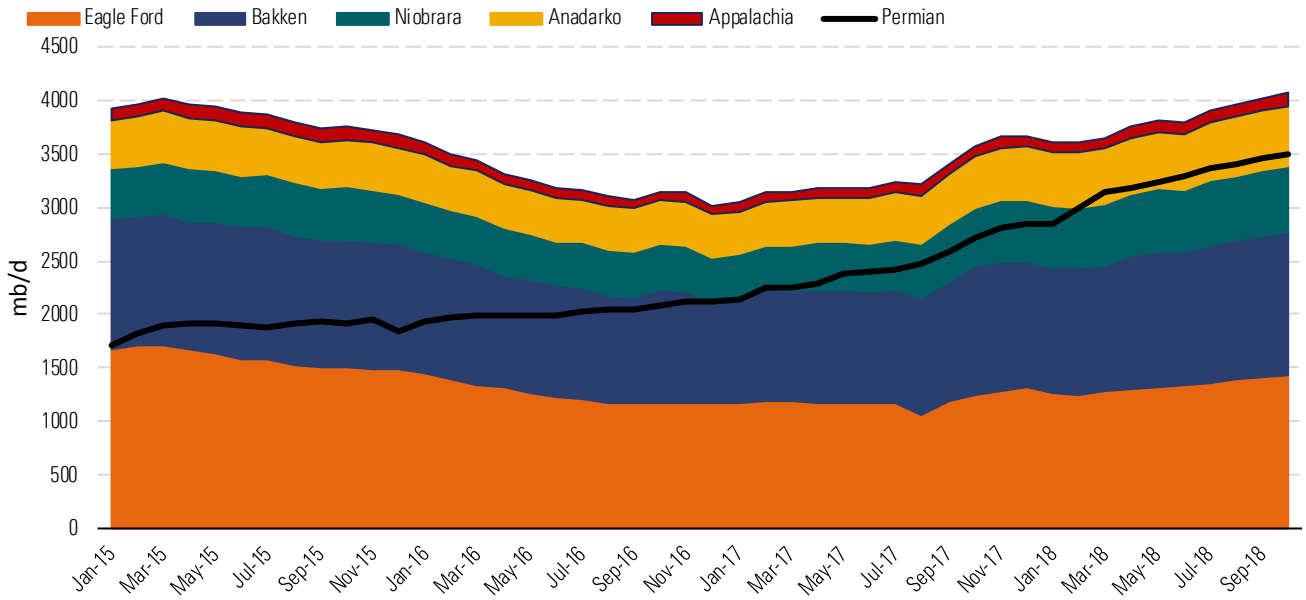
According to the Energy Information Administration's latest monthly report, total U.S. crude output jumped a whopping 382 thousand barrels/day between July and August to a record 11.3 million barrels/day – up 2.1 mmb/d year on year. The jump put U.S. crude on top of the world producer list for August and reminds us that output continues to break records despite takeaway capacity constraints. Monthly production has now increased by 2.8 mmb/d since its recent low of 8.5 mmb/d in September 2016 following the price crash in 2015. According to EIA's monthly Drilling Productivity report, at least 1.5 mmb/d of that growth came from the Permian basin, but the West Texas behemoth lost some of its momentum this year. This note compares recent Permian output with the rest of the shale basins and reviews prospects for producers looking at alternatives.

Growth Engine

The Permian has been the growth engine of U.S. crude production since the price crash brought the first shale boom to an end in March 2015. At that time, overall shale crude production peaked at 5.9 mmb/d according to the EIA Drilling Productivity Report covering the top six basins. Permian output of 1.9 mmb/d in March 2015 represented 32% of that total. Overall shale output declined from April 2015 on – bottoming out at 5.1 mmb/d in September 2016. However, Permian production increased throughout this period despite a much lower rig count – raising its share to 40% that month. In the two years since then (through October 2018) higher prices and lower extraction costs prompted a 2.5 mmb/d recovery in shale production across the major basins, led by the Permian, where output increased by 1.5 mmb/d - propelling it to a 46% share.

Exhibit 1 shows how rapidly Permian crude output (black line) has grown relative to the other five basins covered by the EIA Drilling Productivity Report since 2015 (shaded areas, stacked). However, in the past six months – between April and October - non-Permian shale crude outpaced the West Texas behemoth – up by 325 mb/d compared with a 312 mb/d increase in the Permian. This change came about because of strong growth this year in the South Texas Eagle Ford and North Dakota Bakken basins, together with a leveling off of Permian output as a result of pipeline takeaway congestion (see our August note: "The Permian Triangle – Midland Discounts Encourage Exports").

Exhibit 1 Crude Production in Top Six Shale Basins Since January 2015



Source: EIA, Morningstar

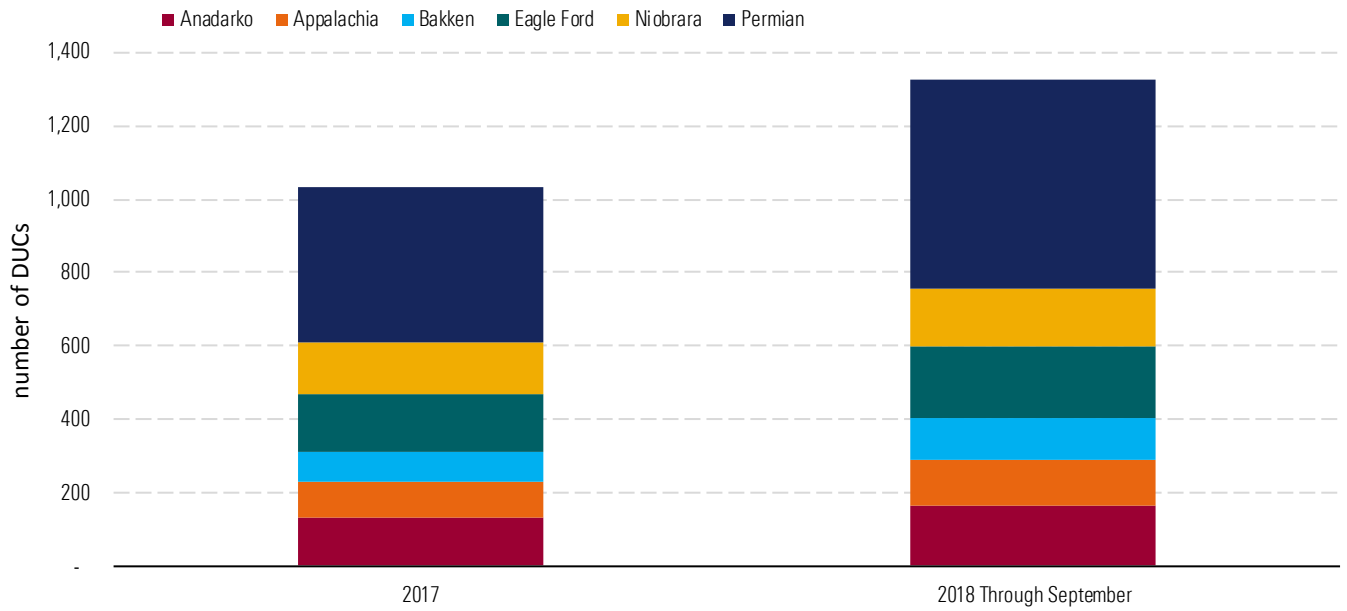
Less Productive Drilling

Although the Permian has been the growth engine for shale crude, drilling rigs have been more productive in other basins. Permian output per new rig, as reported by the EIA Drilling Productivity Report peaked at an annual average 672/b/d in 2016 and declined to an estimated average 592 b/d between January and November 2018. Equivalent output per new rig in the Eagle Ford averaged 1575 b/d in 2016, falling to 1424 b/d in the first 10 months of 2018, which is still more than twice the Permian level. Average per rig crude output in the Bakken and Niobrara basins this year reached their highest level so far at 1477 b/d and 1184 b/d respectively. Higher output per new rig seen in the Eagle Ford, Bakken and Niobrara formations suggests that producers in these regions have been more selective in their drilling and concentrated on sweet spots that produce high initial output to keep drilling breakeven prices lower.

DUCs in a Row

The recent slowing of Permian crude production growth has been precipitated by increased congestion in pipeline takeaway capacity out of the region. That has discounted prices, leading to producers keeping oil in the ground once the well is drilled in hopes of better revenue in the future when new transport capacity opens. The result is a big increase in wells drilled but uncompleted or DUCs, meaning the well has not been fracked to begin producing. DUCs increased more than 4 times as fast in the Permian this year than in other basins. According to the EIA, Permian DUCs were up by 1369 between December 2017 and September 2018 compared to an increase of 302 in the Eagle Ford and 251 in the Anadarko and a fall in DUCs in the Niobrara and Appalachian basins (Exhibit 2).

Exhibit 2 Number of DUCs per Basin 2017 and 2018 Through September



Source: EIA, Morningstar

Yet the intensity of drilling this year remains nearly 3 times higher in the Permian than the next most popular basin – the Eagle Ford. Between January and September the average wells drilled per month in the Permian were 567 (41% of total shale wells) versus 198 in the Eagle Ford (14%), 167 in the Anadarko (12%), 156 in the Niobrara (11%), 122 in Appalachia (9%) and 113 in the Bakken (8%).

Our sense is that producers still regard the Permian as the best long-term growth basin for drilling and production. Despite some slowdown in productivity and output, the Permian continues to attract massive midstream investment and producers benefit from associated production of natural gas and gas liquids out of the complex multi-layered Permian geology. The proximity to the Gulf Coast refining and export markets, as well as conduits to the Midwest, adds to the basin's attraction, as does the close link between its principal crude West Texas Intermediate and the CME Nymex futures market that makes hedging future production more efficient.

Other Basins

In an environment of consistently higher prices since the second half of 2017 and rising costs for Permian acreage, drilling and production, producers have transferred some of their focus to other basins and that trend has increased this year.

Eagle Ford

The Eagle Ford is a close by alternative to Permian congestion that has attracted significant investment – most notably BP's $10.5 billion purchase of BHP Billiton's acreage in the basin this year. The Eagle

Ford in South Texas is closer to the Gulf Coast than the Permian and existing spare capacity on Eagle Ford pipelines into Corpus Christi and Houston mean no congestion or discounts for today's crude production. Longer term, producers can piggyback onto at least two planned pipelines from the Permian that run through the basin. The EPIC (Eagle Ford Permian Ingleside and Corpus) pipeline being built by a private equity consortium including Ares Management, TexStar, Castleton Commodities and Ironwood will have as much as 900 mb/d capacity when completed in the third quarter of 2019, split between Permian and Eagle Ford producers. The 900 mb/d Phillips 66 (75%) and Marathon (25%) joint venture Gray Oak pipeline, also due online by Q3 2019 will run from the Permian to Corpus with a lateral running through the Eagle Ford to Freeport on the Gulf Coast near to Houston and the Phillips 66 Sweeny refinery.

As we pointed out in a September note ("U.S. Condensate to Replace Sanctioned Iranian Barrels") there is export demand for the ultra-light crude known as condensate typically produced in the Eagle Ford. Condensate splitters constructed in Corpus Christi and Houston over the past four years as well as additional light crude capacity added by Texas refiners that we detailed in a July 2016 note ("Gulf Coast Refiners Penalized for Running the Lights") adds up to domestic demand for close to 1 million b/d of very light crude. All these factors should continue to attract drilling investment. Eagle Ford output is up by 362 mb/d in the 15 months since it bottomed out at 1.06 mmb/d in August 2017 and we expect that momentum to continue.

Bakken and Niobrara

Further away from the Gulf Coast epicenter of crude export activity are the North Dakota Williston basin, home of Bakken shale crude, and the Niobrara formation running through the Rockies in Colorado (Denver Julesburg basin) and Wyoming (Powder River basin). Bakken crude production is up 40% or 385 mb/d since its post-price crash low point in December 2016 at an estimated 1341 mb/d in October 2018 according to EIA. Over the same period, Niobrara output is up over 50% by 212 mb/d to 620 mb/d in October 2018. As pointed out above, rig productivity in both these basins is at record levels this year. However, in the short term, Bakken production has run into congestion issues as it competes for pipeline space into the Midwest with equivalent light sweet Canadian crude. The more direct Dakota Access pipeline from North Dakota to Patoka, Illinois and Nederland on the Texas Gulf Coast is also filling up rapidly. Takeaway relief for expanding Bakken production is promised via a 100 mb/d expansion of DAPL by Energy Transfer although no in-service date has been announced.

There's still plenty of pipeline capacity for Niobrara barrels but all roads out of the Rockies lead to Cushing, Oklahoma, which has less outbound capacity than inbound. With additional crude trying to get out of the Permian via Cushing, the Midwest hub remains a congestion point for barrels trying to reach Gulf Coast export points. New pipeline capacity is on the way to get crude out of Cushing in the short term with Enterprise promising to add 100 mb/d to the Seaway pipeline using drag reducing agents by the end of 2018 and longer term via the proposed 800 mb/d Tallgrass Seahorse pipeline from Cushing to St. James, Louisiana, which won't be built until the end of 2021 at earliest.

These congestion issues getting new Bakken and Niobrara barrels to market from north of Cushing are reminiscent of struggles during the first shale crude boom when infrastructure took a while to catch up with expanding output. Midstream development, now largely funded by private equity, favors the more popular Permian and Eagle Ford basins where drilling rates are higher and distances to market lower.

Established players in the Bakken such as Continental, Hess and Phillips 66 have an incumbent advantage and access to long distance pipelines, but newer entrants need to factor in transport hurdles even as they contemplate higher well productivity. In the meantime, Proposition 112 on the November ballot in Colorado, which requires a near half mile setback from buildings for new well permits could sabotage that state's production at the source.

Anadarko and Appalachia

The two other basins covered by the EIA Drilling Productivity Report are the Anadarko, in Oklahoma and the Texas Panhandle, and Appalachia, which includes the huge Marcellus and Utica shale gas basins in Pennsylvania, Ohio and West Virginia. Of these the Appalachia basin is still primarily gas-centric with most oil produced in the form of condensate from gas liquids. That means gas drilling largely drives output, which has increased rapidly this year as new gas takeaway capacity out of the Northeast has come online. As a result, EIA estimates that Appalachia crude output is up 23% to 128 mb/d between December 2017 and October 2018, but the region remains a target for gas and gas liquids rather than crude given its distance from the Gulf Coast refining and export markets.

Crude production from the Anadarko basin increased 67 mb/d since December 2017 to a total of 565 mb/d in October according to EIA. Much of this increase is from the prolific STACK and SCOOP plays. These are attractive to producers because of their proximity to Cushing and the Midwest refining market. However, with plenty of alternative supply from further north coming into Cushing, the basin needs expanded access to the Gulf Coast to encourage continued growth.

Summary

The Permian remains king of the hill for crude producers and midstream infrastructure development with the focus of takeaway capacity now directed to Gulf Coast exports. However, Permian growth has dipped in the past six months in response to infrastructure constraints that have affected prices and bumped up DUC inventories. Producers are looking to other basins for better and cheaper drilling opportunities – and finding better productivity. However, apart from the Eagle Ford, which has similar geographic advantages to the Permian (proximity to the Gulf Coast), the remaining basins all suffer from varying degrees of takeaway capacity constraint, a lot of it centered on Cushing. So, while an increase in drilling in the Bakken, Niobrara and Anadarko basins has helped propel non-Permian output this year, that trend is likely to reverse once new pipelines relieve Permian congestion at the end of 2019.

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