The Permian Basin Produces Gas, Too

Permian Basin Oil and Gas Production Growth: A Case Study for Gas Infrastructure Needs in the U.S.

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Special thanks to Emily Medina for her contribution on Mexico's infrastructure

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ABOUT THIS REPORT

This report is part of the Energy Policy Research Foundation's multi-year research program evaluating the scale and scope of the North American petroleum renaissance. As U.S. producers expand production to meet domestic requirements and the rapidly growing market for pipeline exports and Liquefied Natural Gas (LNG), it is essential that policy makers have a full understanding of the sustainability of the U.S. natural gas production platform. This report addresses the range of challenges and opportunities for expanding U.S. production of natural gas for both domestic uses and export markets through an in depth look at North America's most prolific oil and gas basin, the Permian.

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INTRODUCTION

Oil and natural gas production in the nearly century-old Permian Basin surged in recent years as operators transitioned from vertical to horizontal drilling combined with hydraulic fracturing. This ongoing application of "unconventional" technology, in what was an aging conventional play, unlocked multiple stacked payzones (reservoirs) and reversed years of production declines. This rapid growth, over 2 mbd (million barrels per day) in just eight years, put pressure on existing midstream infrastructure and pipeline transportation capacity within the basin. Oil production that has risen to over 3 mbd is setting new records for the basin and creating bottlenecks in infrastructure for both oil and gas takeaway capacity. These midstream bottlenecks should not present a long-term threat to growth if infrastructure projects remain on track, but the Permian may face intermittent hurdles in the coming years as projects roll online.

Rising associated gas volumes with no home arguably present the largest growth constraint. Recent growth in Permian oil production drove natural gas production from 4.5 Bcf/d (billion cubic feet per day) in 2010 to over 9.5 Bcf/d at present and associated water production to an astounding 16 mbd. These associated gas volumes are a byproduct of the oil production process and require large amounts of infrastructure for gathering, processing, and transportation. Unlike crude oil, which can be hauled away by truck or train, natural gas must be transported to market by pipeline from the wellhead. The region is struggling to keep up and without additional infrastructure development, especially for natural gas, steady growth will be put at risk and operators may be forced to curb production.

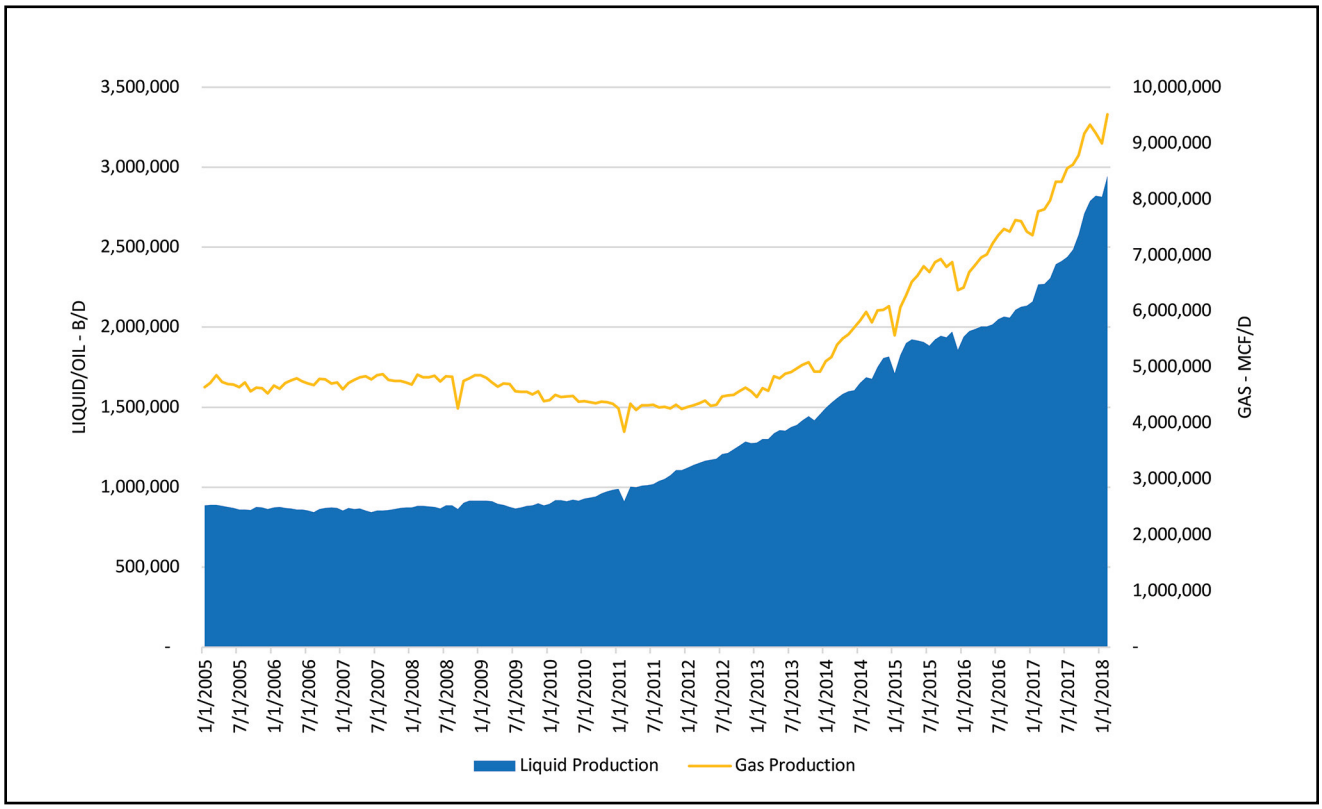
The pursuit of oil is driving E&P activity in the Permian, but from a technical perspective the growth in oil production is driven partly by associated gas. The sharp rise in gas output from oil wells shocked many analysts in the Wall Street community in 2017 and dinged the equity values of several Permian-centric operators. As operators have continued to modify and enhance completions techniques, oil output has continued to rise in tandem with gas production.

This report seeks to explain the rapid rise in oil and gas production in the Permian Basin and need for natural gas infrastructure both within and outside of the basin.

KEY FINDINGS

- The dramatic rise in oil production, almost exclusively from horizontal wells, brought with it a surge in associated natural gas production. This associated gas is a byproduct of the crude oil production process. As crude oil production has risen over 2 mbd since 2010, natural gas production also grew by over 5 Bcf/day.
- Productivity gains, mainly from longer laterals and enhanced completions, are a relatively new phenomenon, and are driving large volumes of both oil and gas production from the wellbore. The continued gains in productivity, increasing the amount of oil output per well, also resulted in increased gas output. Because lateral lengths still average under 8,000 feet and completion techniques, well spacing, and asset delineation continue, PetroNerds believes these productivity gains will endure (although perhaps not on a per lateral foot basis).
- The rise in oil and gas production has created severe near-term bottlenecks in the basin. Both natural gas and crude infrastructure development have lagged the rapid pace of growth for both products and the lack of takeaway capacity is pressuring prices at the wellhead. The price of natural gas is less of a concern for many operators because oil makes up most of the revenue stream, but the need to pipe and process the gas remains imperative. Operators must find a home for their natural gas and require flow assurance to keep drilling and producing oil.
- In a hypothetical "maintenance" scenario in which necessary oil and gas infrastructure projects are delayed and only present-day takeaway capacity is available, Permian Basin activity would decline by approximately one-third to maintain oil production of 3 mbd until late 2019.

Figure 1
Permian Basin Oil and Natural Gas Production



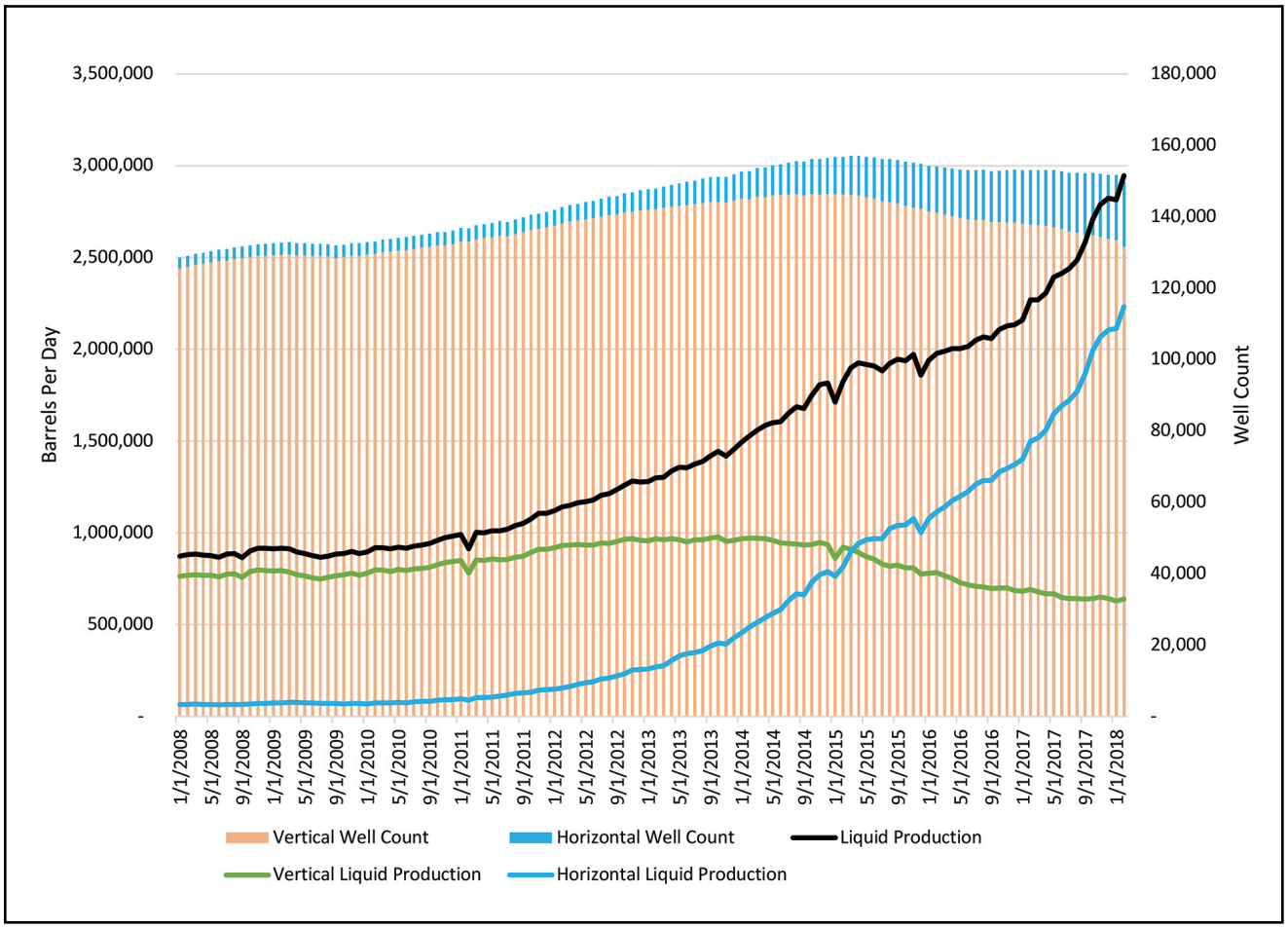
Source: PetroNerds, DrillingInfo

PRODUCTION FROM HORIZONTAL WELLS AND PRODUCTIVITY GAINS

Rising oil prices over the past year partially incentivized recent Permian Basin drilling and completion activity, but prices are hardly the only factor at play. Operators began to noticeably increase Permian production in 2011 in a $100/b oil price environment. Growth, however, remained robust in a sub-$60/b price environment following the 2014 price crash. This robustness can be attributed to a number factors, including stringent leasing requirements, which require production on land to hold acreage. Furthermore, investor pressure and the need to delineate assets also pushed operators to add new wells.

Following the rapid ascent of the Bakken and Eagle Ford unconventional oil plays, unconventional development quickly took hold in the Permian. Note in Figure 2 below that the vertical well count, currently over 120,000 wells, declined from its 2014 peak for four years running. The addition of approximately 18,000 horizontal wells offset the fall in vertical development. These horizontal wells, which account for slightly less than 15% of active Permian Basin wells, are responsible for over two-thirds of the Basin's 3 mbd of oil production.

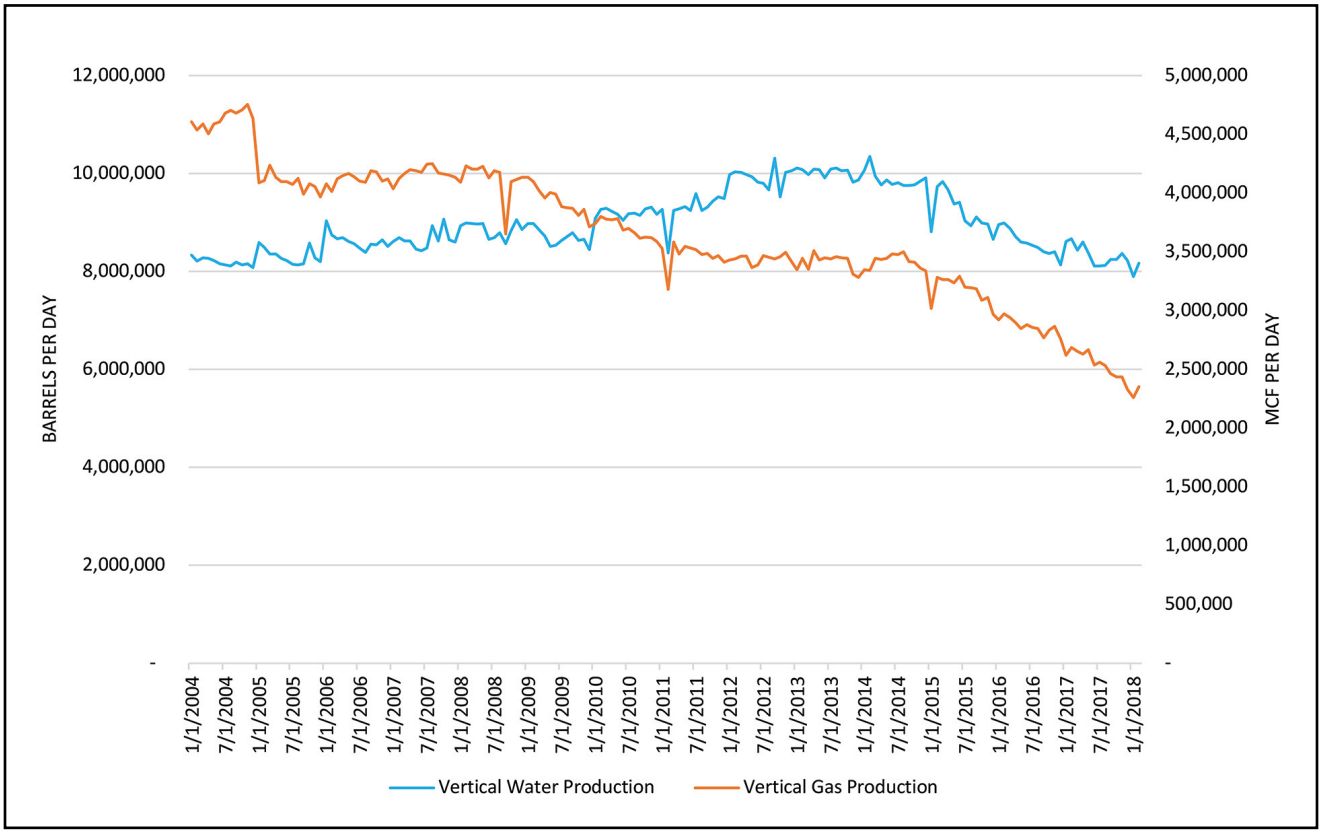
Figure 2
Permian Basin Vertical and Horizontal Well Counts and Oil Production



Source: PetroNerds, DrillingInfo

Figure 3 below shows gas and associated water production from vertical wells. Gas production has declined precipitously to just 2.3 Bcf/d. Water production has not fallen to the same extent as gas and sits at approximately 8 mbd.

Figure 3
Gas and Water Production from Vertical Wells



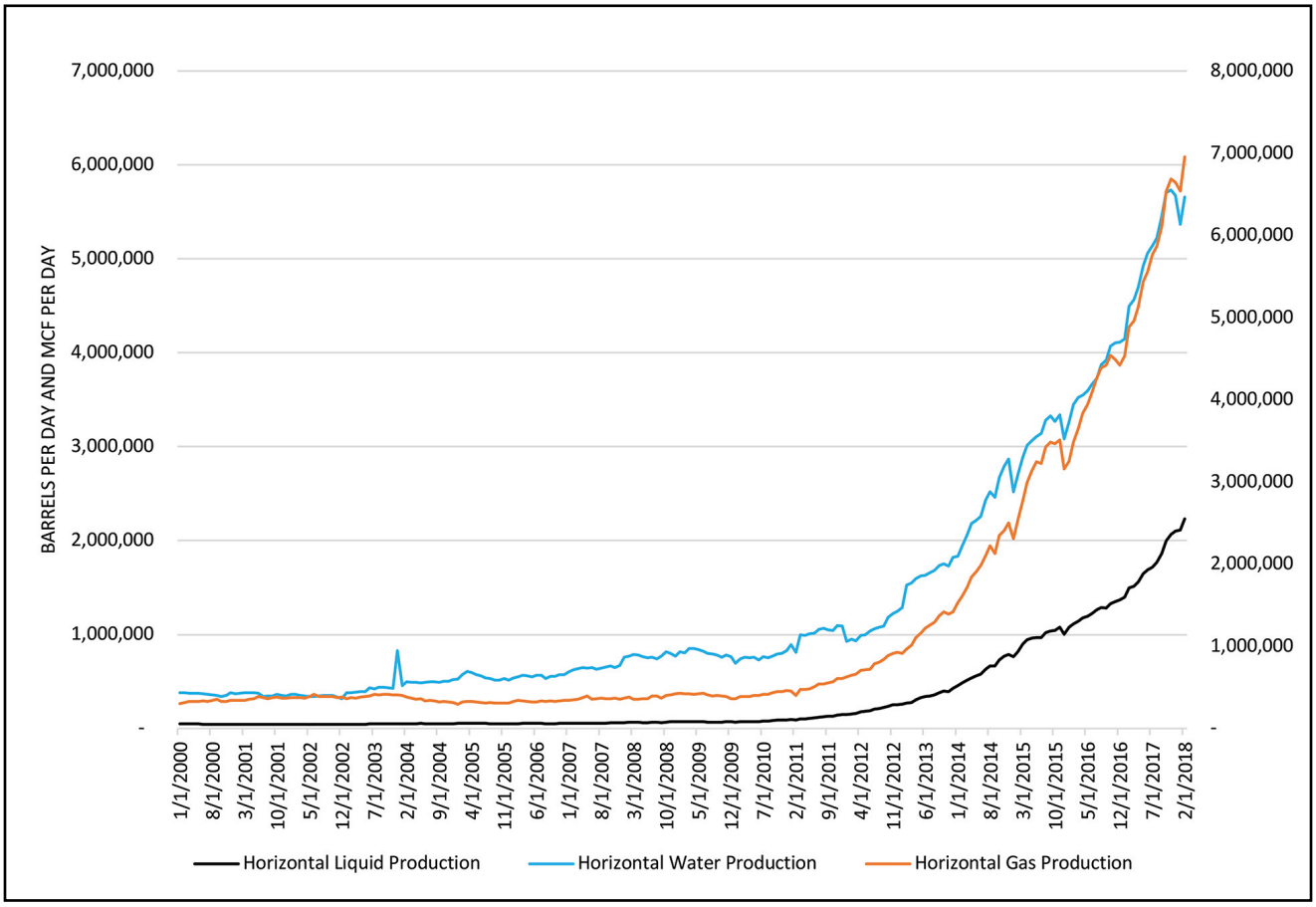
Source: PetroNerds, DrillingInfo.

The brief period of growth in oil production from vertical wells between 2011 and 2014 came about as operators tested and learned about the Permian's stacked pay zones. Vertical wells were inexpensive relative to horizontal wells in other shale plays and employed by some operators as an early delineation tool. While many of the larger players already moved into horizontal drilling mode by the time oil prices dropped in 2014, smaller and medium size players quickly switched gears and began aggressive horizontal drilling and hydraulic fracturing campaigns to boost output over the course of the downturn, leading to robust horizontal well growth despite sustained sub-$60/b prices. Enhanced completion techniques, which involve the utilization of more fluid and more proppant per lateral foot than typical unconventional wells, also contributed to output growth. Additionally, stringent leasing requirements and the need to drill and produce to hold acreage also kept activity elevated throughout the downturn.

Production growth is also aided by the ability of operators to continually improve well performance and increase productivity across the basin's prolific geology and stacked payzones. The figure below shows horizontal liquid, water, and gas production. Natural gas production rose from just under 1 Bcf/d in 2012 to 7 Bcf/d today, comprising over 70% of gas production in the basin. While vertical wells still contribute a significant amount of water in the basin, horizontal wells are producing nearly 6 mbd of water alone. The impressive

completion gains that operators made, enhancing completions with more sand (proppant) and often more fluid, (water or linear gel) has increased oil, gas, and water output. Certain areas of the basin produce more gas than others, but broadly speaking gas and water productivity gains now reflect the trajectory of oil.

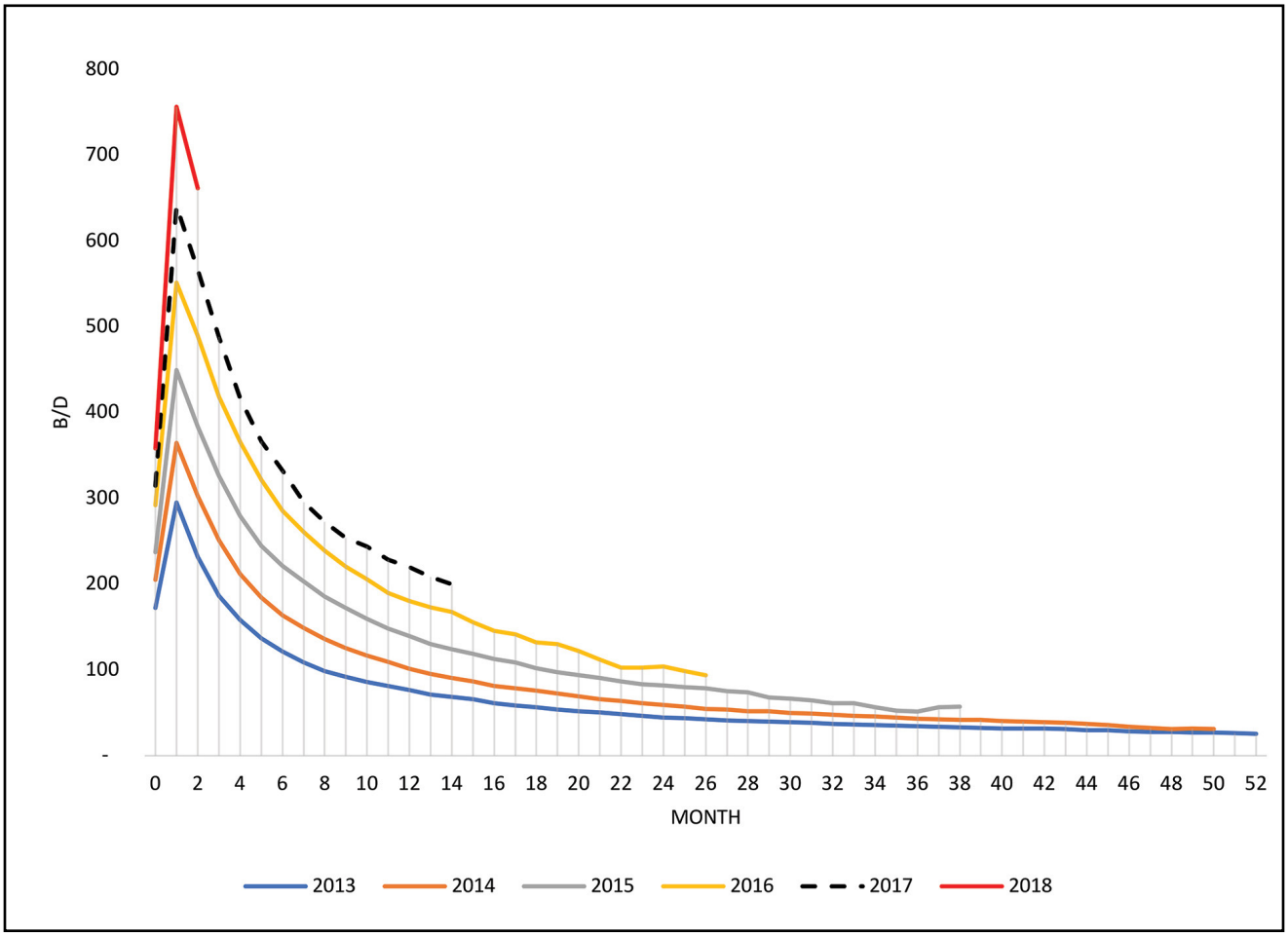
Figure 4
Horizontal Oil, Gas, and Water Production



Source: PetroNerds, DrillingInfo

Advances in completions, enhanced understanding of reservoirs, and longer laterals contributed to productivity gains in Permian Basin oil production. The figure below shows year over year productivity gains in oil output for horizontal wells in the Permian Basin. It does not normalize for lateral lengths.

Figure 5
Horizontal Oil Type Curves

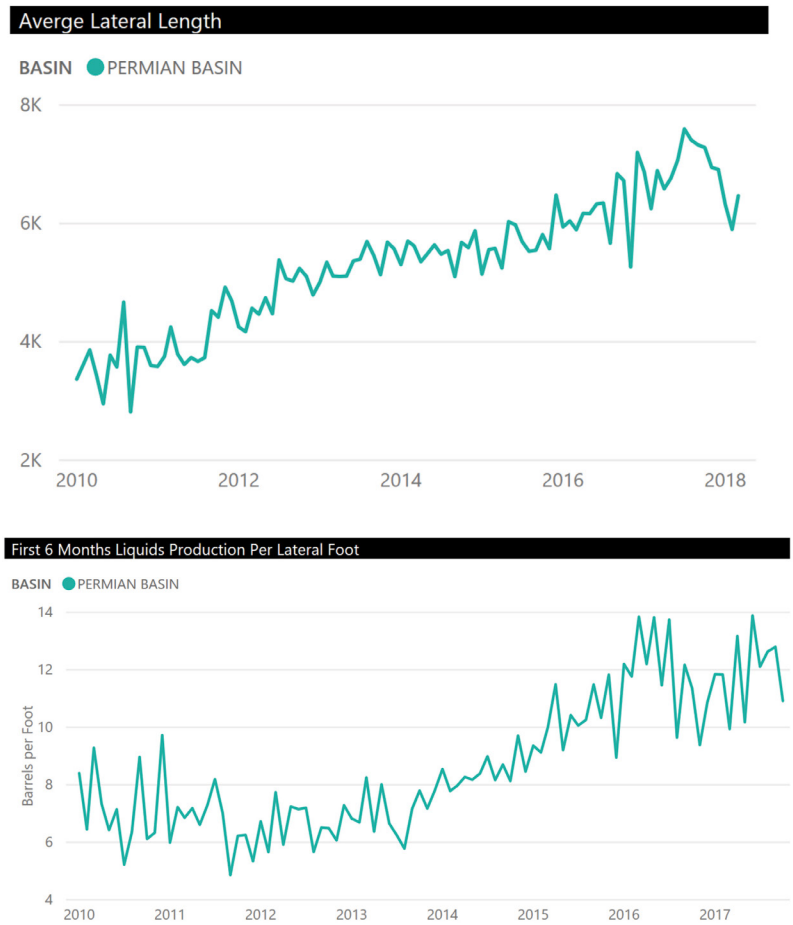


Source: PetroNerds, DrillingInfo

PRODUCTION FROM HORIZONTAL WELLS AND PRODUCTIVITY GAINS continued

Figure 6 shows the average lateral length for horizontal Permian Basin wells overtime. Some operators still utilize shorter laterals, especially when there are acreage limitations; however, longer laterals in conjunction with multi-well pads typically offer cost and productivity efficiencies. As an unconventional play, the Permian is relatively young compared to the Eagle Ford and Bakken. Lateral lengths are still increasing, and operators are just beginning to employ wide-scale pad drilling, so efficiency gains are likely to continue within the basin. Figures X. below shows the average lateral lengths and first six-month cumulative oil production per lateral foot in the Permian Basin.

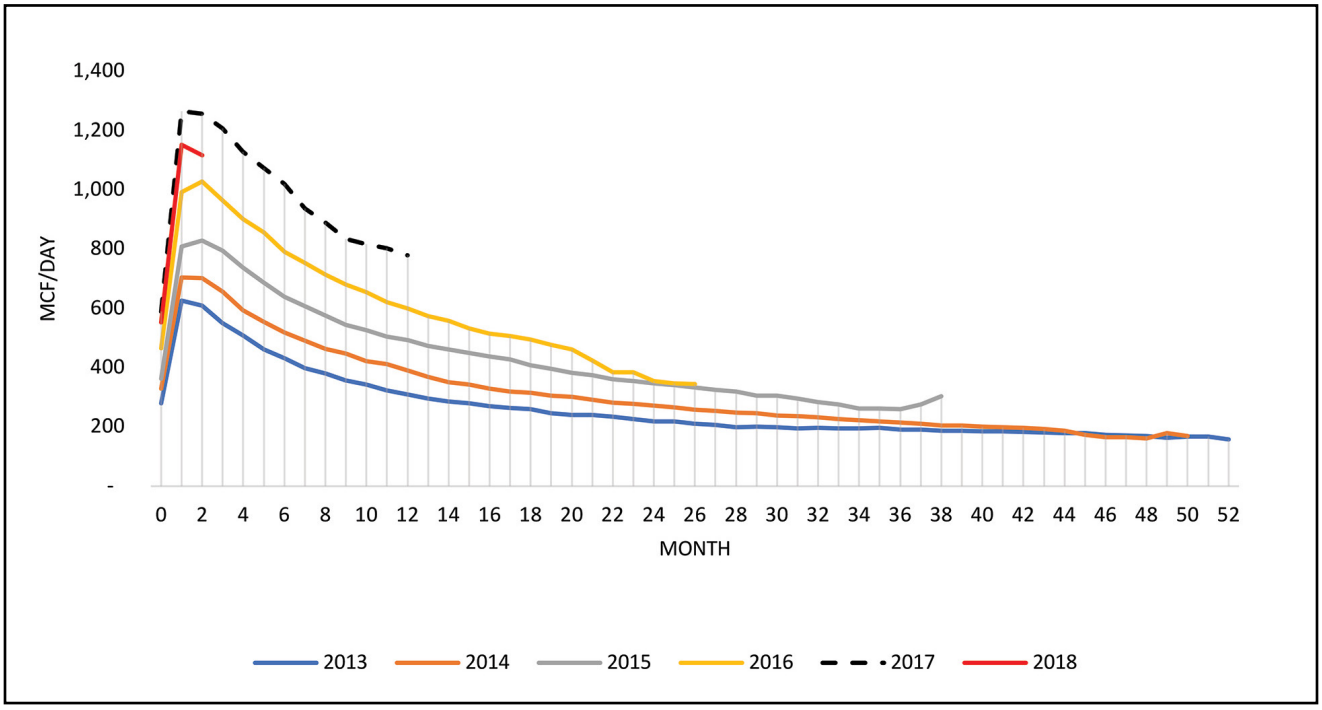
Figure 6
Permian Basin Average Lateral Lengths and First 6 Month Cumulative Oil Production per Lateral Foot



Source: PetroNerds, DrillingInfo

Productivity improvements directly contributed to the need for both oil and gas infrastructure. Just as the oil type/decline curve illustrates year over year gains, so does the gas curve depicted below. The average initial production rate for gas from horizontal wells in 2017 was nearly 1,300 mcf/day. A 2017 horizontal well produces twice as much gas in its first year in production as does a 2014 well. Growth in gas productivity combined with relatively inelastic development has overwhelmed the Basin's ability to handle associated gas.

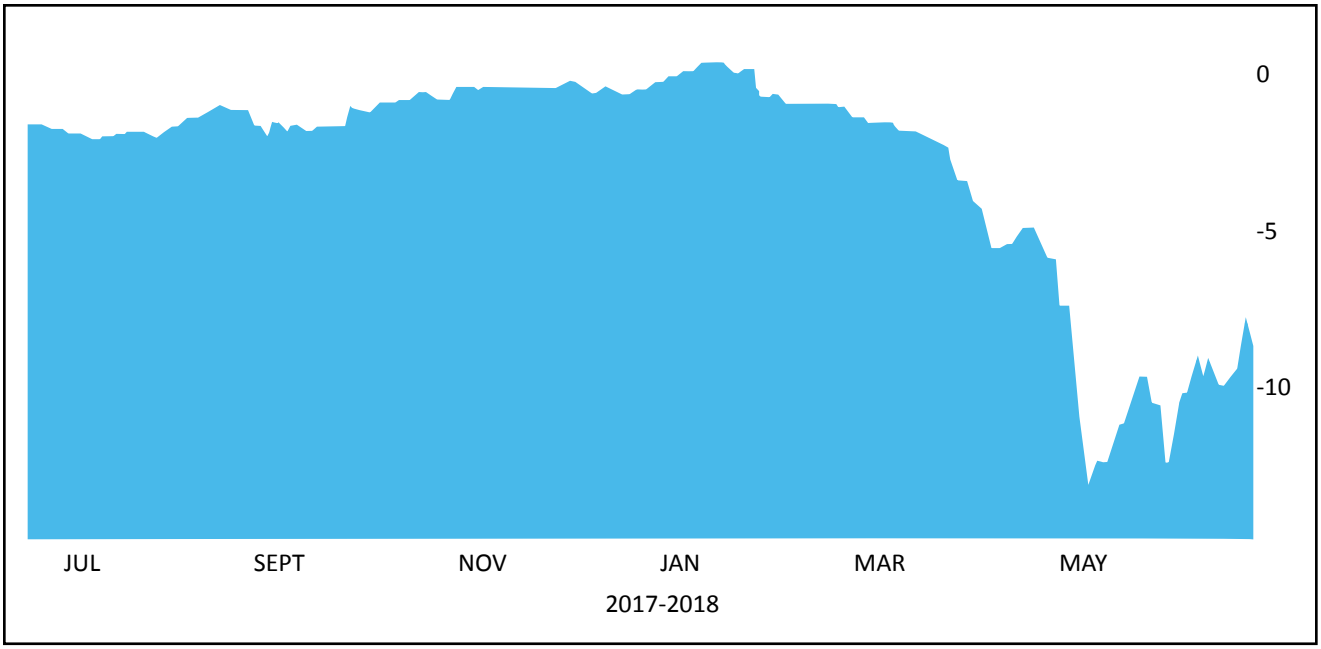
Figure 7
Horizontal Gas Type Curves



Source: PetroNerds, DrillingInfo

The surge in Permian oil and gas production volumes to record levels has left the midstream sector scrambling to catch up. Some operators are still enjoying spare pipeline capacity and can ship incremental volumes to desirable market centers, but many are currently selling their crude at the wellhead within the basin, receiving substantial discounts from WTI (West Texas Intermediate). Figure 8. below shows the spread between WTI Midland and WTI Cushing crude oil over the past year, as reflected in the NYMEX futures market. WTI Midland currently sells at a discount of approximate $8/b to WTI Cushing, up from a low of $13/b at the end of April.

Figure 8
WTI Midland vs. WTI Financial Futures, NYMEX ($/b)



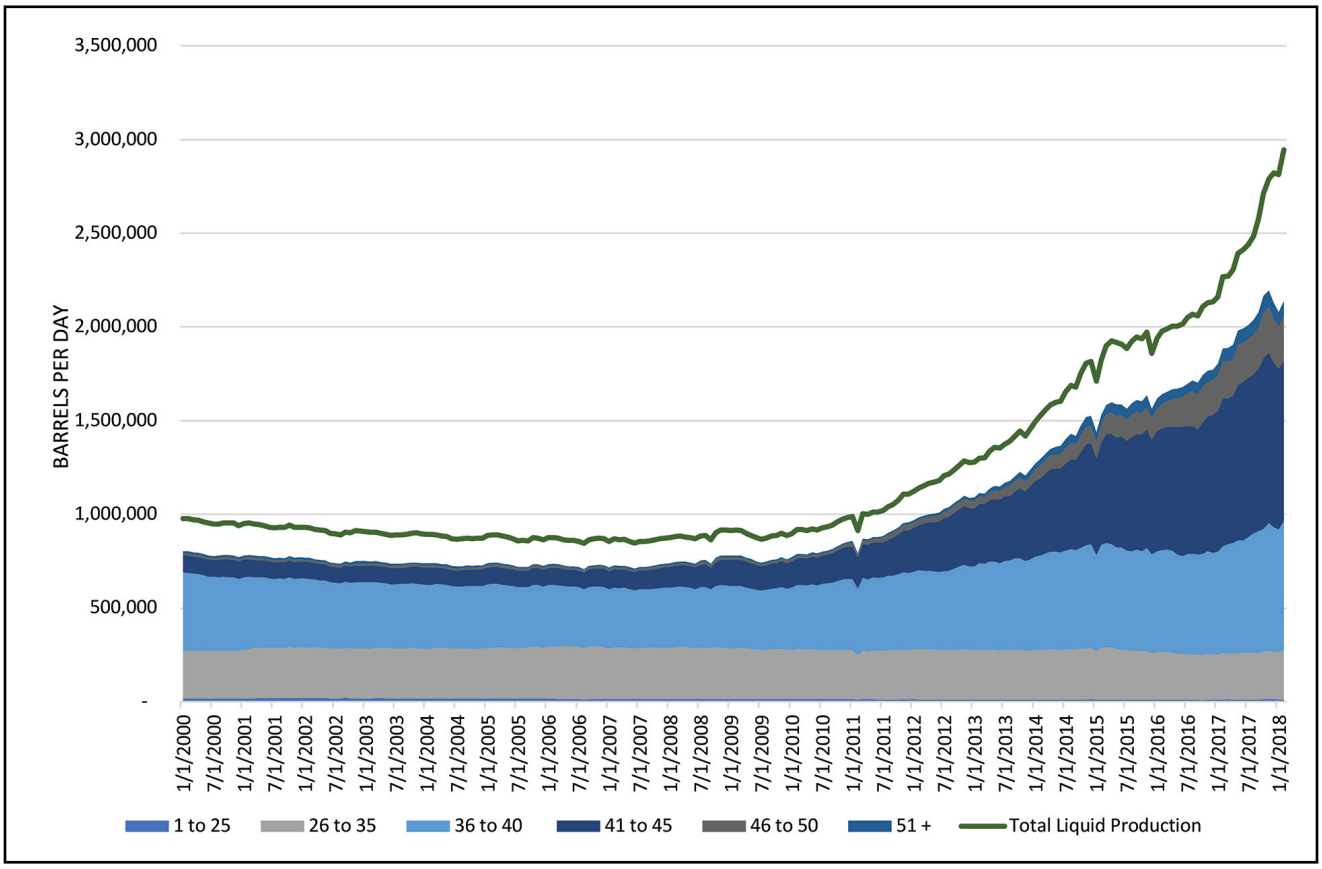
Source: Tradingview

To overcome this discount, Permian operators are clamoring to move their crude to higher value markets such as the Gulf Coast or Cushing hub. Many are also using basis swaps to lock in differentials in financial markets. Several pipelines are slated to come online over the course of 2019 and 2020, providing long-term solutions to the bottleneck. Temporary solutions, such as rail and truck shipping, are being utilized but are very costly. For growth to continue, multiple pipelines will need to be built, much of them to the Gulf Coast, allowing for higher netbacks due to export optionality and access to global markets.

GEOLOGIC COMPLEXITY, API GRAVITY, AND GAS TO OIL RATIO

The Permian Basin's geologic complexity plays a direct role in the composition of products. Abundant amounts of natural gas and water are mixed in the crude oil stream. As oil output has risen, so has natural gas. The Permian Basin is composed of the Wolfcamp, Leonard, Avalon, and Bone Spring formations that contain multiple stacked reservoirs, typically interbedded sandstones, shales, and carbonates. Here, like in other basins, the geology dictates the type of oil operators extract from the reservoir, including the API gravity of the crude oil which indicates how light or heavy it is. Typically, tight oil is often found in rock that is both deeper and tighter than conventional sources. This means it has not escaped into a trap and has potentially cooked longer than nearby conventional oil and is therefore lighter on an API gravity scale. The Bakken formation produces relatively consistent crude at 43 API. The Eagle Ford deepens and becomes more thermally mature as one moves north to south and west to east, transitioning from oil to condensate to dry gas. This discrepancy creates a wide gravity range for both crude oil and condensate. The prevalence of stacked payzones in the Permian Basin also creates varying pockets of API gravity ranges. Figure 9 below shows production by API gravity by ranges. DrillingInfo data, collected from state data, is missing API gravity figures for nearly 1 mbd of production, but the chart still illustrates the growth in production of light crude oils, largely between 41 to 45 API gravity.

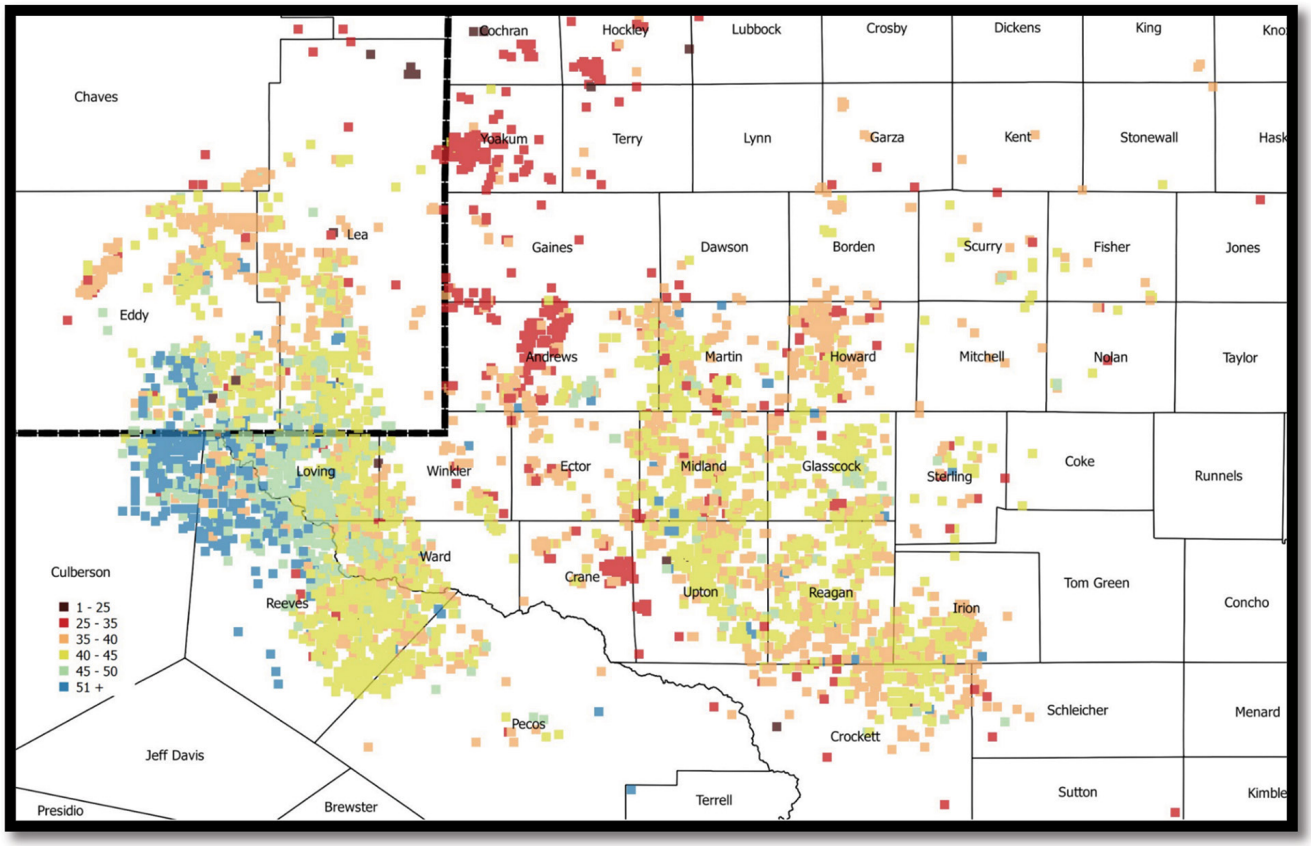
Figure 9
Permian Basin Production by API Gravity



Source: PetroNerds, DrillingInfo Note: API gravity for some volumes is reported as unknown or "0."

The figure below shows a geographic distribution of production by API gravity. There are regions with production closer to condensate than crude oil at 51+ API gravity (blue region), particularly on the western side of the Delaware Basin.

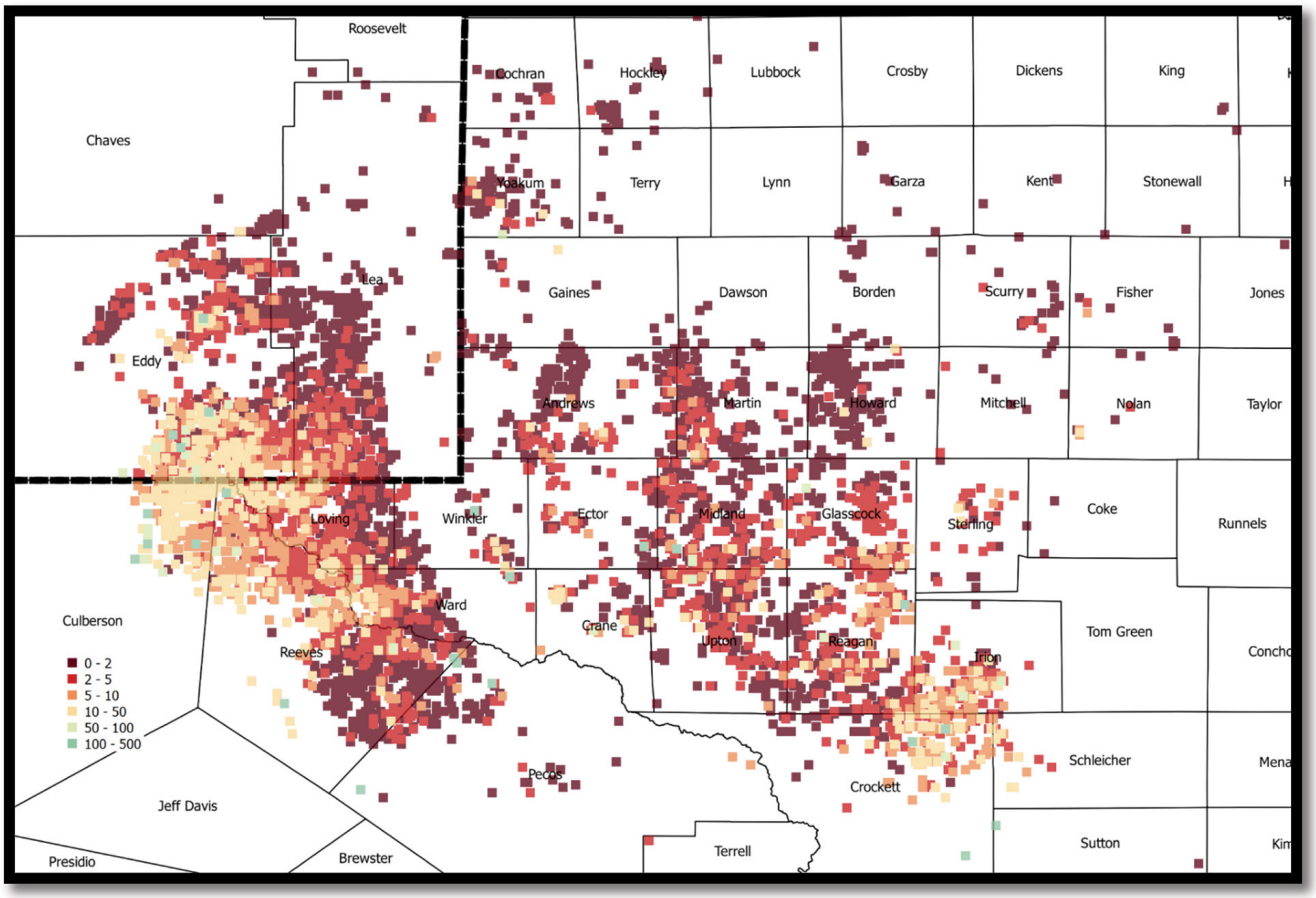
Figure 10
Map of Production by API Gravity



Source: PetroNerds, DrillingInfo

These areas of higher API gravity tend to also have a higher gas to oil ratio (GOR). The figure below illustrates a geographic connection between higher API gravity and a higher gas to oil ratio, particularly in the 10 to 50 mcf/barrel range.

Figure 11
Map of Production by GOR

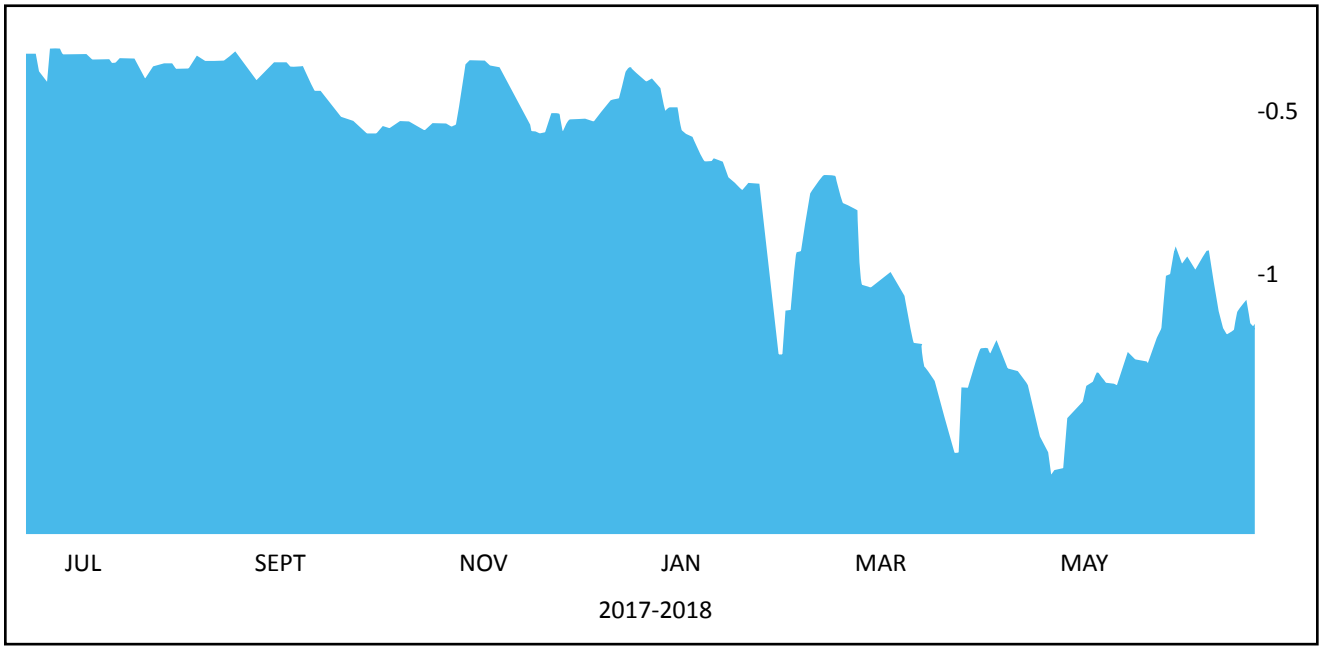


Source: PetroNerds, DrillingInfo

UNDERSTANDING THE INFRASTRUCTURE CONSTRAINTS

The abrupt rise in Permian Basin oil and natural gas production outpaced infrastructure development and created transportation bottlenecks. These bottlenecks are ultimately evidenced by steep price discounts for crude oil and natural gas within the Permian Basin. Natural gas discounts in Waha, the Permian Basin hub, are well over a dollar under Henry Hub. Some analysts expect the value of gas at Waha to move to zero sometime this year, implying that there is so much gas in the region that producers will have to give it away for free in order to find a home for it. Figure 12 below shows Waha Basis Futures, the discount for natural gas at Waha relative to Henry Hub.

Figure 12
Waha Basis Futures, NYMEX ($/mmbtu)



Source: Tradingview

Operators face two primary dilemmas with associated gas production. One is the difficulty operators face in getting their associated natural gas captured and moved to market. The second is earning revenue for their natural gas (this is generally less of a concern right now, which depends upon the operator and their share of revenues from natural gas within the Permian Basin). At present, the primary concern is moving gas to market so that operators can continue to drill, complete, and increase oil production. If one cannot get gas to market, that gas must be flared. Flaring creates several complications, including pressure from the environmental community and lost revenues. Texas currently allows operators to flare their wells for up to 45 days (with some longer-term exceptions available). Most operators are assuming this window will not be expanded in the advent of further bottlenecks and infrastructure constraints. Permian operator Centennial Resource Development stated the following in their Q1 2018 earnings call:

> *Since the beginning of last year, it has been our goal that we ensure our crude oil production will not be curtailed or shut in due to potential gas constraints. Additionally, we are operating under the assumption that the Texas Railroad Commission will not allow us or the industry to flare gas for an extended period when takeaway capacity is full. Therefore, Centennial has put several transportation service agreements in place in order to ensure delivery of its natural gas to market.*

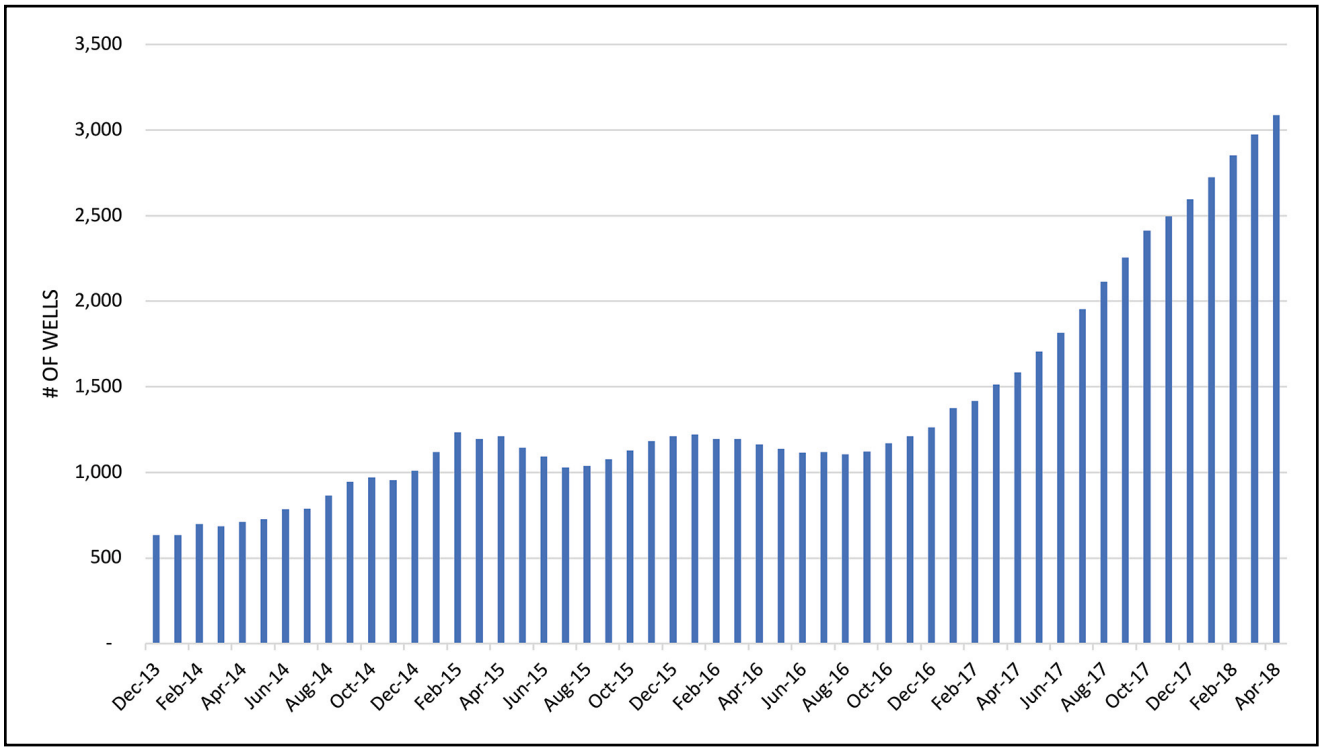
Centennial Resource Development, Q1 2018 Earnings Call, Seeking Alpha

The core issue for the Permian is that not all companies have adequate gas transportation agreements in place. Midstream bottlenecks are not a new problem in oil play development and plagued essentially every unconventional oil and gas play in the U.S. over the past decade. The Denver Julesburg Basin currently faces oil output constraints as operators actively choke back wells while awaiting gas processing plant capacity to come online. Flaring became a contentious issue in the Bakken; at one point, over 30 percent of associated gas production was being flared and the state of North Dakota faced significant environmental criticism. Measures were put in place and the state significantly reduced flaring through volumetric targets and more accurate measuring, but mostly the reduction in flaring was a result of additional pipelines and processing capacity coming online. Similar growing pains are being felt in the Permian Basin, but on a much greater scale.

A plethora of projects for both natural gas and crude oil are slated to come online over the next couple years, but these timelines could cause constraints in output in the short-term. Currently, Permian natural gas flows into the Waha hub and then onward in multiple directions, mostly flowing both east and west out of Texas and New Mexico. Some gas volumes also move north out of Waha and south into Mexico. A major Mexican pipeline, El Encino-La Laguna, mentioned below, will come online later in 2018, helping to move some Permian gas to Mexico. Kinder Morgan's Gulf Coast Express pipeline is slated to come online in late 2019 with a capacity of 2 Bcf/day. Tellurian, a liquefied natural gas exporting company, has planned a Permian gas pipeline, Permian Global Access Pipeline, which could bring gas to the Gulf Coast as early as 2021. Many other pipelines are in the works and they are expected to bring sizeable volumes of natural gas from the Permian Basin to the Gulf Coast, potentially creating new natural gas congestion issues in the early 2020s.

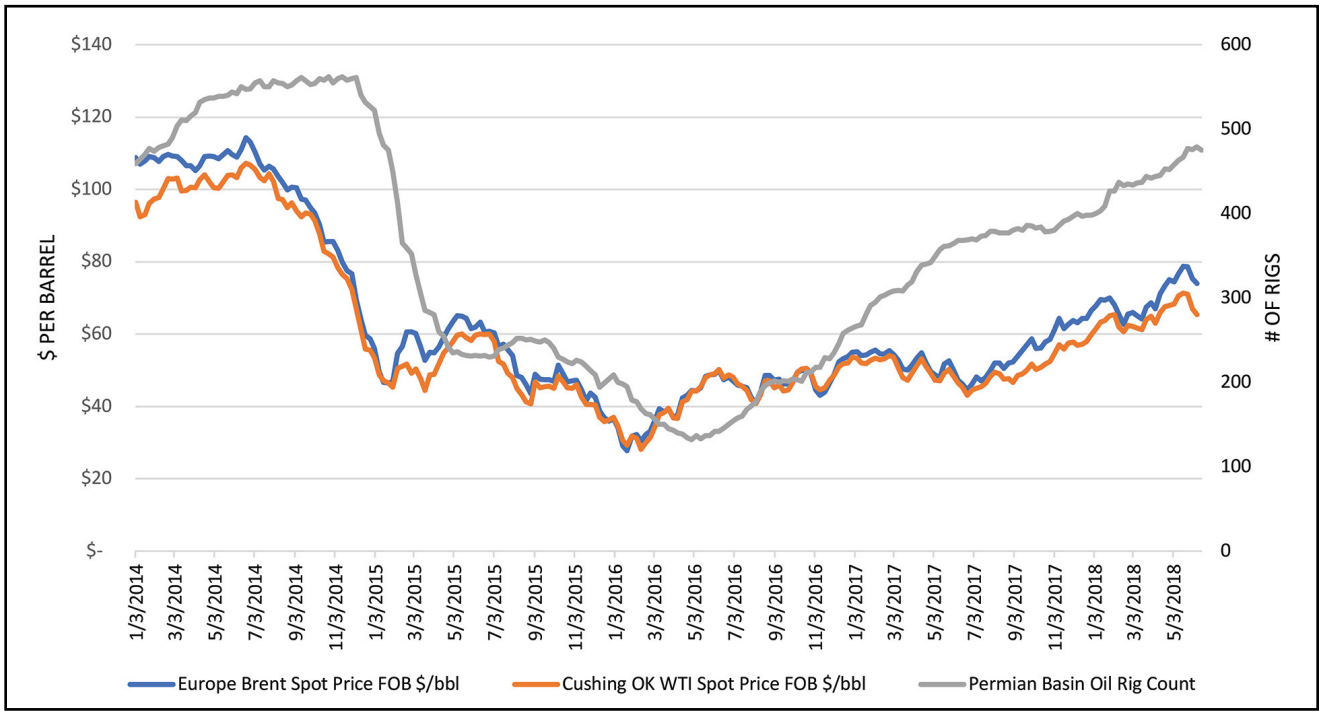
Currently, gas constraints likely pose a more immediate short-term threat to overall oil output growth in the Permian Basin than oil infrastructure constraints. Some operators are in a better position than others to deal with this over the course of 2018 and 2019 due to their commitments with midstream providers for gas. These natural gas constraints, or the ability to move additional and growing volumes of natural gas, are more likely to impact crude oil production than costly oil transportation options (trucking or rail). However, both could impact the number of drilled but uncompleted wells (DUCs) for individual operators. Note the DUC count has been rising in the Permian Basin since late 2016 along with the rise in the rig count and oil prices.

Figure 13
Permian DUCs



Source: EIA data

Figure 14
Oil Prices and Permian Rig Count



Source: EIA, Baker Hughes

Natural gas infrastructure must be diligently developed from the wellhead to the end user if the basin is going to keep growing oil production. Increasing volumes of natural gas need to be moved out of Waha and to the Gulf Coast where the gas can either be processed and sent to the consumer or exported via LNG (liquefied natural gas). Mexico also plays an increasingly important role here: the Permian is increasingly dependent on Mexican demand growth as a means for alleviating natural gas bottlenecks.

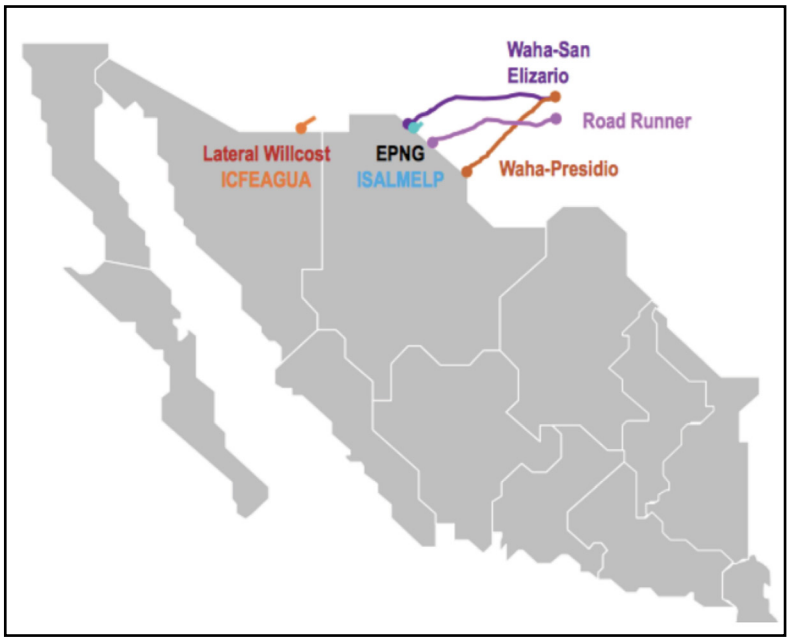
Gas Exports to Mexico

Rising gas production, particularly in the southern part of the Permian Basin (Delaware side), has created an immediate need to push additional volumes of gas into Mexico from the Waha hub in the Permian Basin. While Mexico increased its cross-border pipeline expansion in recent years to allow U.S. gas to flow into Mexico and offset its declining domestic energy supply, there are still several obstacles before it can increase its natural gas capacity in-take. Infrastructure delays within Mexico's distribution network place a capacity cap on existing pipelines. Therefore, the nearly 3.5 Bcf/d of nameplate capacity out of the Permian Basin into Mexico is misleading as Mexico does not yet have the infrastructure in place to capture this gas and move it to the appropriate demand centers.

Three pipelines came online in 2017 to help bring natural gas from the Permian Basin into Mexico. Trans-Pecos Pipeline and Comanche Trail pipeline are both operated by a consortium between Energy Transfer and Carso Energy, and their capacity is 1.36 Bcf/d each. Oneok, in conjunction with Fermaca, also brought online the Roadrunner pipeline with 0.57 Bcf/d of capacity.

Unfortunately, these pipelines are not met with the necessary infrastructure across the border. These delays are mainly an issue of local land owner opposition and tedious land titling requirements. The El Encino-La Laguna, a national pipeline which will have a capacity of 1.5 Bcf/d, is projected to come online in November 2018. Once that happens, the El Encino-La Laguna is expected to connect with the downstream pipeline, Laguna-Aguascalientes, which extends 442 km further south and reaches Villa de Reyes-Aguascalientes-Guadalajara. These pipelines will have a total capacity of 3.5 Bcf/d, feeding into CFE power plants, and additional pipelines, helping to better match the nameplate capacity above with appropriate capacity and demand across the border in Mexico.

Figure 15
Cross-border Pipelines from the Permian Basin to Mexico



Source: "Avances en la Apertura del Mercado de Gas Natural." *Comisión Reguladora De Energía*, July 11, 2017. Accessed June 01, 2018.

Table 1
Cross-border Pipelines from the Permian Basin to Mexico

Pipeline name	Pipeline developer	Date of operation	Length(km)	Capacity (Bcf/d)	Start point	End point
Trans-Pecos Pipeline (Waha-Presidio)	Energy Transfer/ Carso Energy	Mar-17	238	1.36	Waha hub	Presidio, Texas
Comanche Trail Pipeline (Waha-San Elizario)	Energy Transfer/ Carso Energy	Jan-17	290	1.36	Waha hub	San Elizario, Texas
Road Runner	ONEOK Partners/ Fermaca	Jan-17	321	0.57	Waha hub	San Elizario, Texas
EPNG	Kinder Morgan company	Jul-13	96	0.2	Tucson, Arizona	Sasabe, Arizona
			Total Capacity	3.49		

A special thanks to Emily Medina with EPRINC for her comments and contribution on pipelines to Mexico. More information on Mexican natural gas demand and infrastructure can be found in a report from EPRINC on this topic by Emily Medina.

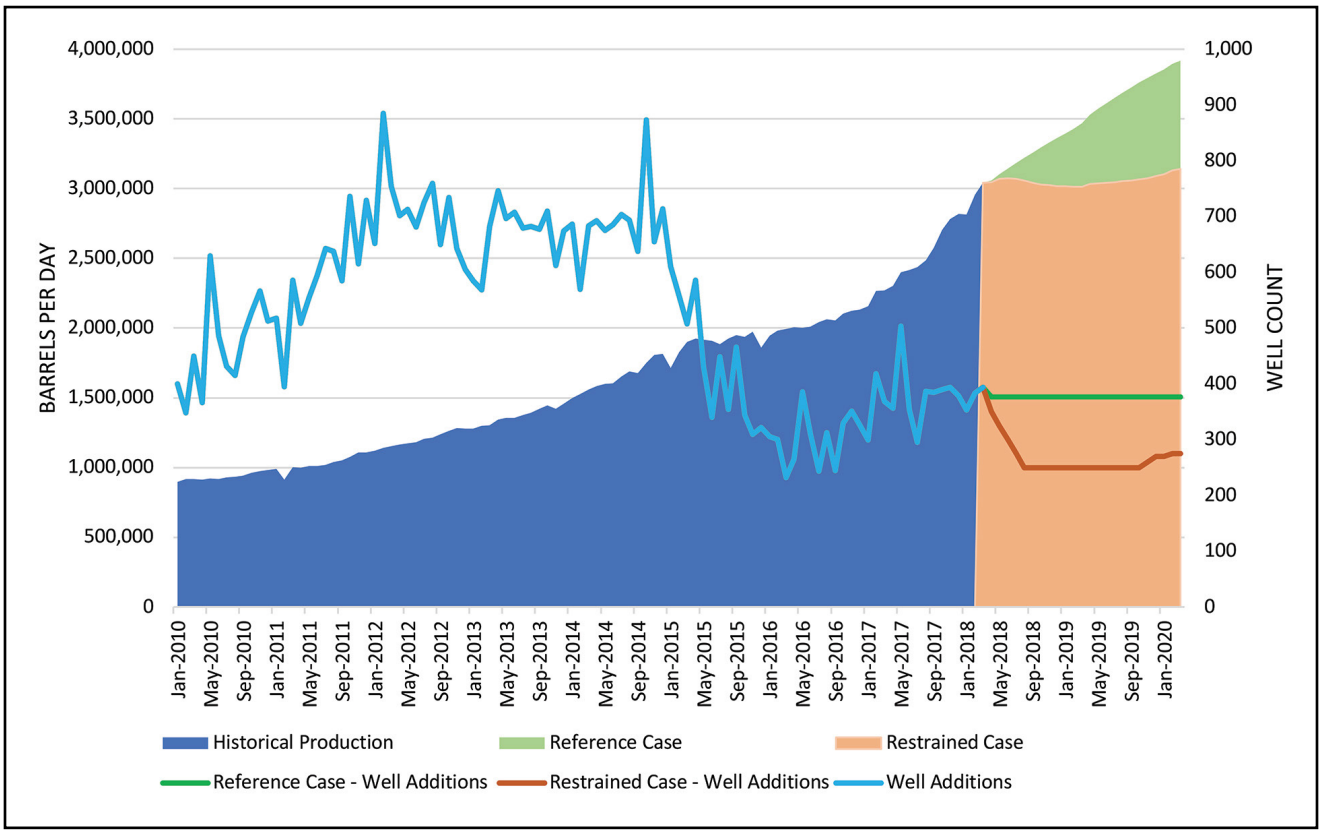
A Note Crude Oil Infrastructure

As with gas, the Permian Basin will see a pipeline buildout and multiple projects are planned and in place to begin moving large volumes of crude as early as 2019. Current providers are increasing capacity incrementally as fast as possible by means of DRAs (Drag Reducing Agents). Multiple midstream providers are moving in to bring online additional capacity for crude oil to the Gulf Coast as early as 2019. Plains All American has two smaller expansions in play that will help move additional volumes to Cushing and to Houston. Magellan still plans to move forward with its 600,000 b/d pipeline to the Gulf Coast and believes it can be in service mid-2019. P66 has a much larger scale pipeline planned called Gray Oak that will bring 1 mbd from the Permian to the Gulf Coast as early as Q4 2019.

CONCLUSION

Figure 16 depicts historical Permian Basin oil production and monthly well additions (among currently active wells) adjacent to two production forecasts. The reference case forecast carries forward current well addition rates and allows for very modest productivity gains while also accounting for declines in producing wells. This is not necessarily a "most likely" scenario, but rather an extrapolation of today's activity levels over the next two years. In this scenario production reaches nearly 4 mbd in early 2020. The hypothetical restrained case, or maintenance scenario, represents a scenario in which needed oil and gas midstream projects are delayed or cancelled, leaving operators to contend with maxed out midstream infrastructure.

Figure 16
Permian Oil Production Forecast and New Well Additions Under Two Scenarios



Source: PetroNerds, DrillingInfo

The restrained case reduces monthly well additions by one-third in late 2018, thus maintaining production at around 3 mbd before beginning to grow again in late 2019. This scenario, while purely hypothetical, reflects several factors which could ultimately lead operators to reduce capital outlays should there be uncertainty regarding both oil and gas takeaway capacity. On the gas side, a lack of takeaway capacity via pipeline would leave operators with only two options: flare or shut-in/withhold new wells. Unlike crude oil, natural gas cannot be readily transported from the wellhead by anything other than pipe. This leaves operators with little alternative but to not produce when no takeaway capacity is available and flaring windows close. Gas flow constraints are further complicated by economic factors on the oil side. The financial spread between WTI Midland and WTI Cushing crude is nearly $10/b. But operators without pipeline access to markets at fixed rates are subject to increasing tariff rates or trucking costs. This could exceed the reported spread. Furthermore, independent Permian operators are mostly hedged

at below $60/b, meaning they are taking a haircut of around $10/b on hedged barrels. Combined, these economic factors may force some operators to reduce capital outlays and activity levels until transportation constraints dissipate.

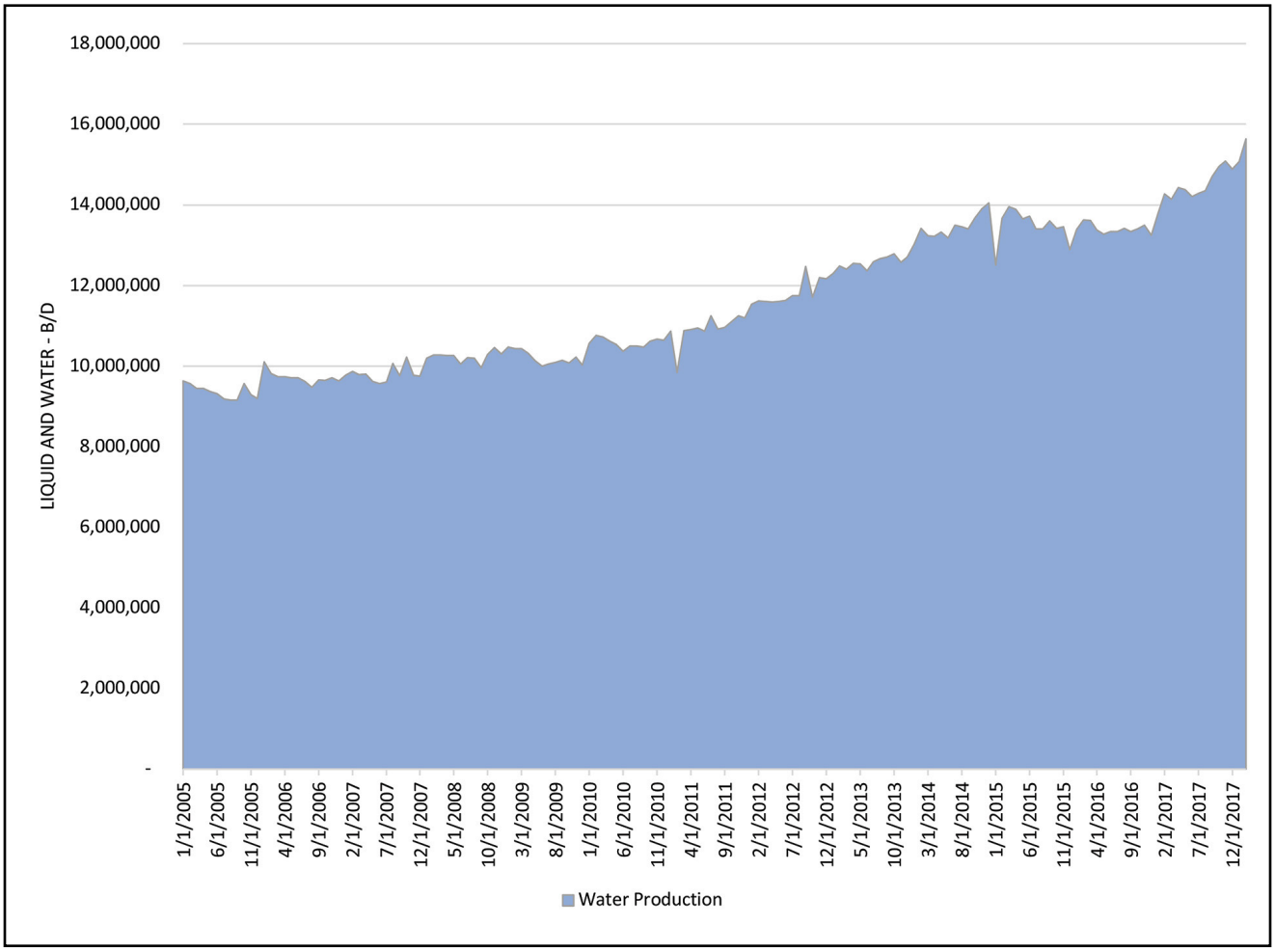
The restrained case effectively works backwards to illustrate what a worst case midstream scenario would look like given a stable $65/b WTI-Cushing price. To work within existing infrastructure availability, well additions and most overall activity levels would need to drop by one third. The loss of nearly 1 mbd of growth over the next two years would significantly impact global prices upwards and reduced activity levels would leave a noticeable economic and employment impact in the US.

In practice, leasing requirements and other non-price-related incentives may mitigate a complete stall in production growth. But without pipeline access for additional barrels, producers will have to move to higher cost methods such as trucking, thus limiting production upside. Associated gas volumes must be dealt with and in the absence of market access, flaring would be at best a controversial and temporary solution.

One tangential benefit is that service costs would likely drop, enabling a more rapid build of the DUC inventory. Ultimately the timing and duration of infrastructure shortages will reverberate throughout oil markets. U.S. shale is being counted on to add significant barrels in the coming years to help meet global demand needs, particularly given the ongoing collapse of Venezuela's oil industry and the reimposed U.S. sanctions on Iran. Infrastructure constraints can and will be sorted out, but the timing and scale of such fixes remain critical.

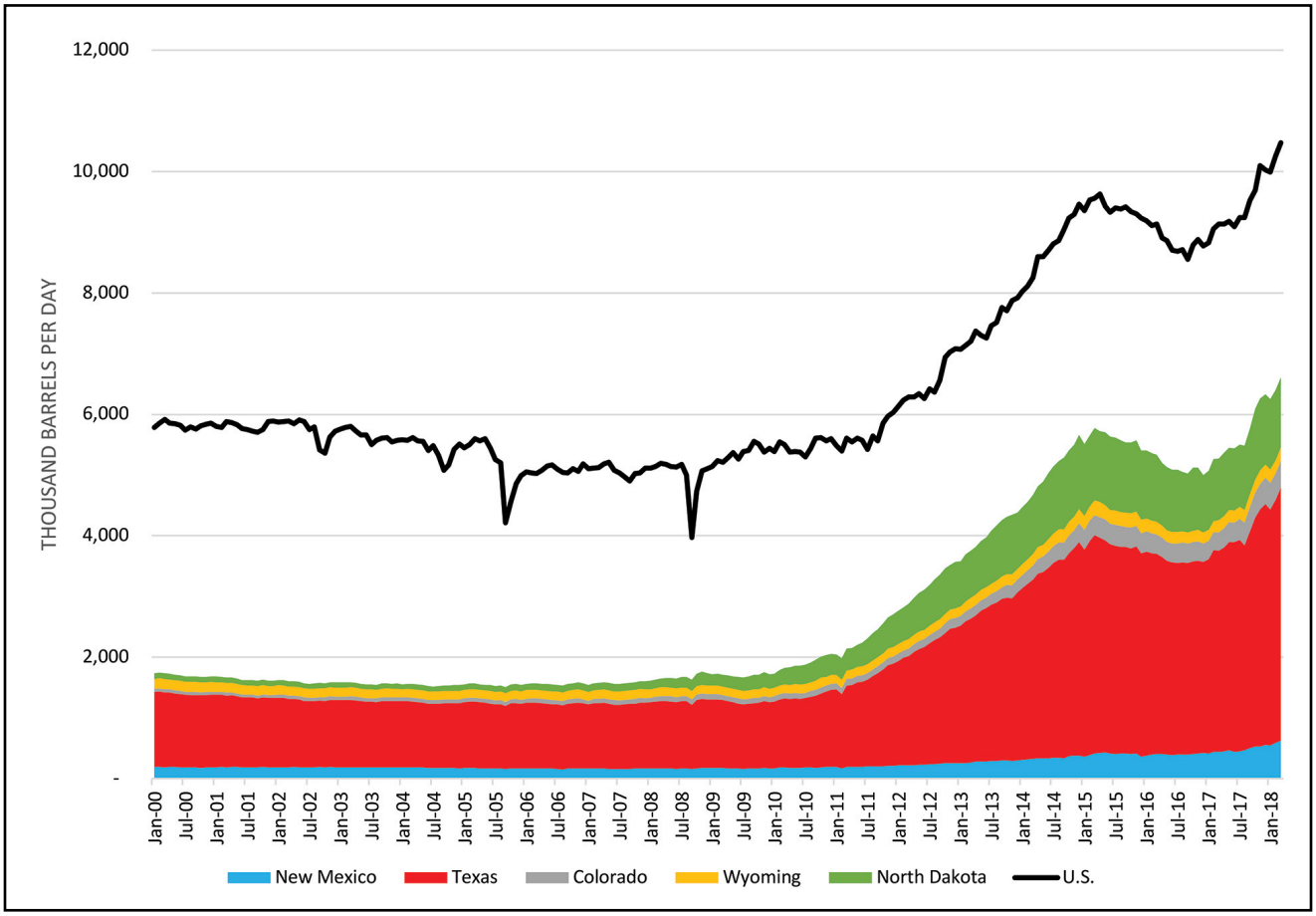
Like the growth in natural gas production from the basin, water production also continued to grow. The Permian Basin historically produces high water volumes, again, due to the geologic nature of the basin; however, horizontal drilling and increased productivity catalyzed a sharp rise in produced water output, along with oil. With produced water comes the need for disposal, and many operators do in fact recycle their produced water and use it for fracing other wells; however, the volumes are significantly higher than could be demanded by fracturing needs. The required disposal of the remaining water means very high volumes of water are being sent to disposal wells. While no significant issues have arisen from this to date, there are concerns about increased seismicity on the Delaware side of the Permian Basin. The costs associated with these high water cuts are steep: higher water production means operators are paying more for disposal costs per barrel of oil produced. The need for effective water transportation, disposal, recycling, and handling is critical for continued oil growth in the Permian Basin.

Figure 17
Permian Basin Water Production



Source: PetroNerds, DrillingInfo

Figure 18
U.S. Production of Crude Oil

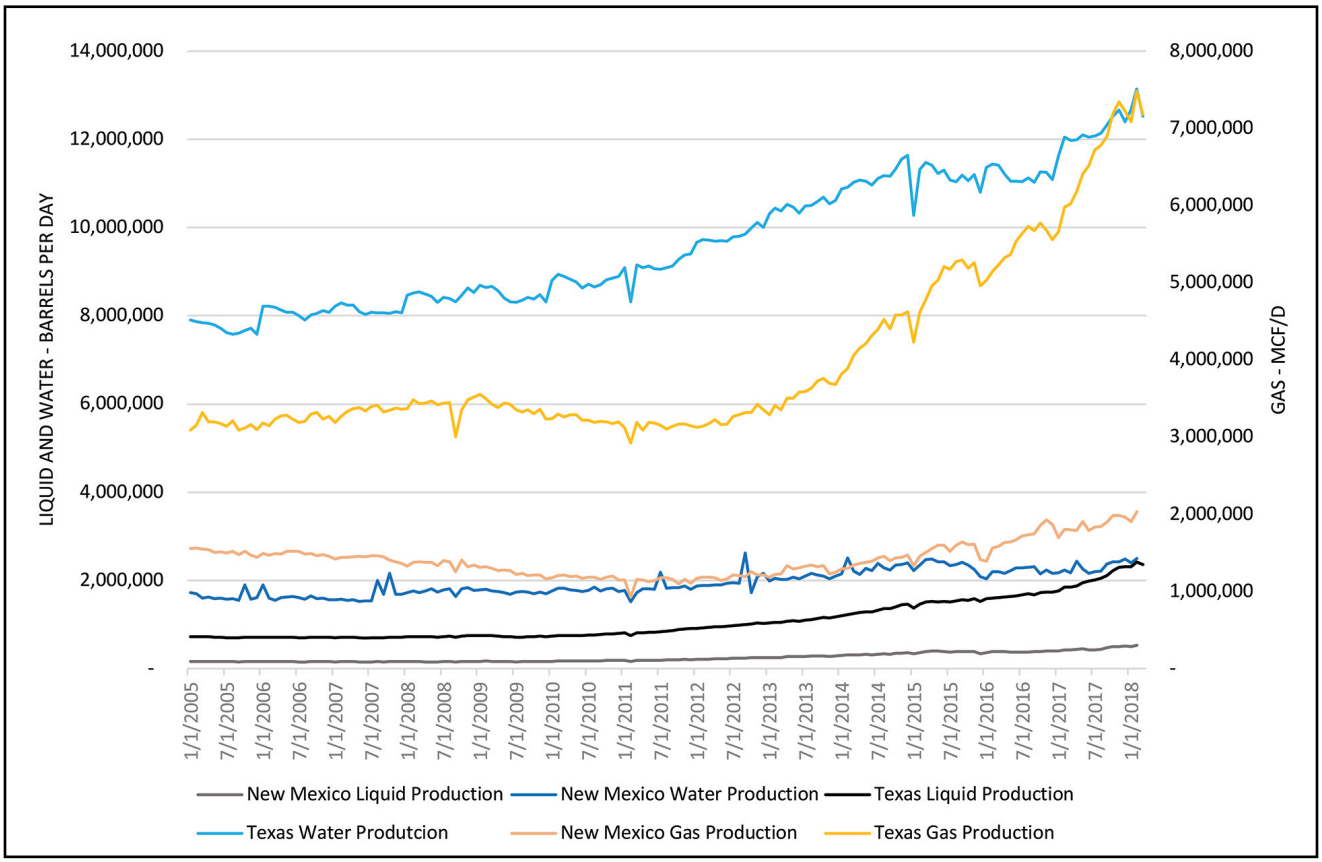


Source: EIA

U.S. production sits at 10.5 mbd as of March 2018. Production continues to rise after a temporary decline, in the face of low oil prices, largely driven by growth from the Permian Basin in Texas and New Mexico. Production from the Permian Basin stands at 3 mbd, contributing to roughly half of U.S. shale/tight/unconventional production. Together, the Williston Basin (Bakken), Eagle Ford, Denver Julesburg Basin, Powder River Basin, and Permian Basin now contribute 6 mbd to U.S. production.

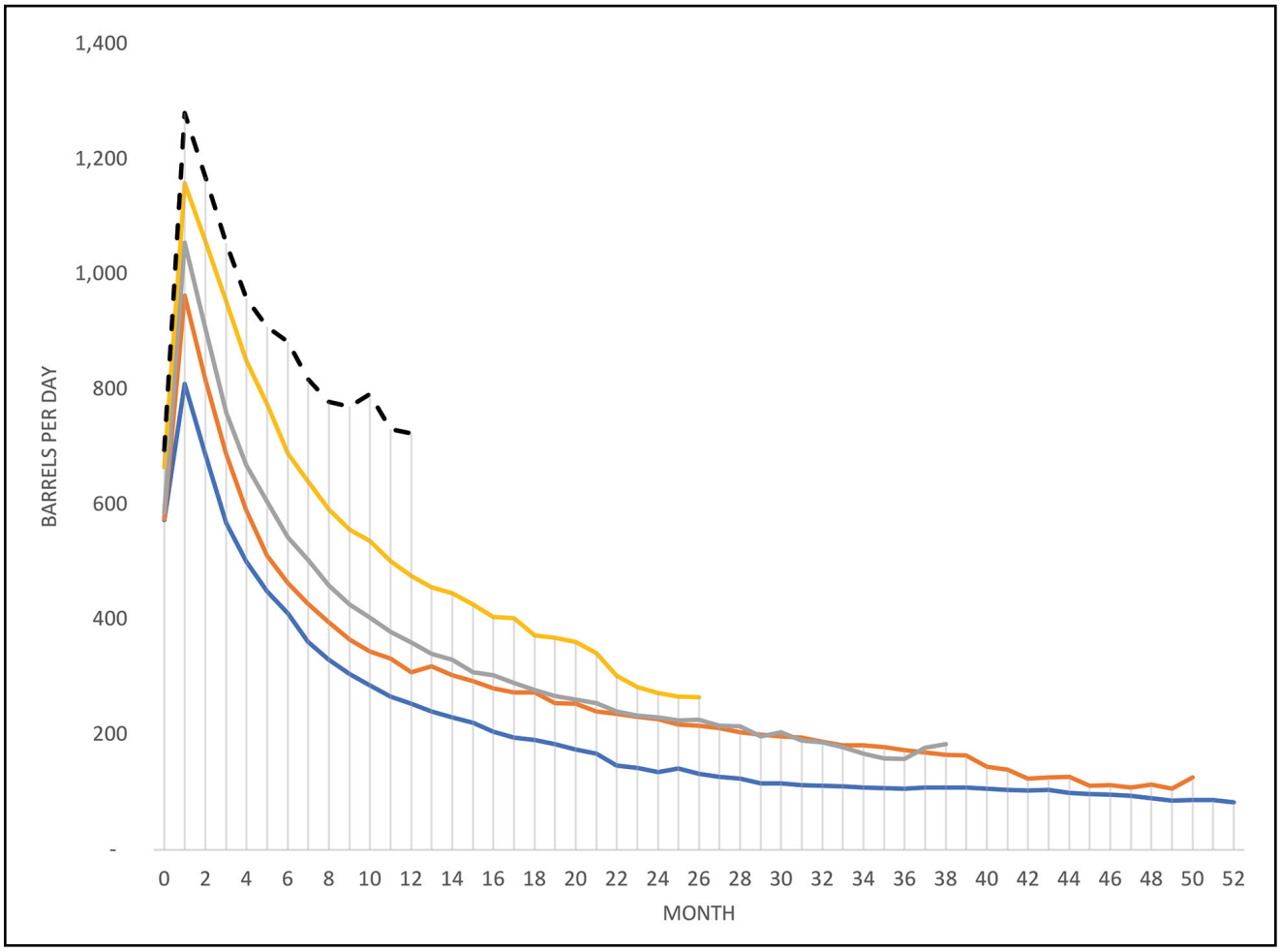
The figures below show the average water production decline curve and average gas production decline curve for horizontal wells in the Permian Basin.

Figure 19
Texas and New Mexico Permian Basin Production



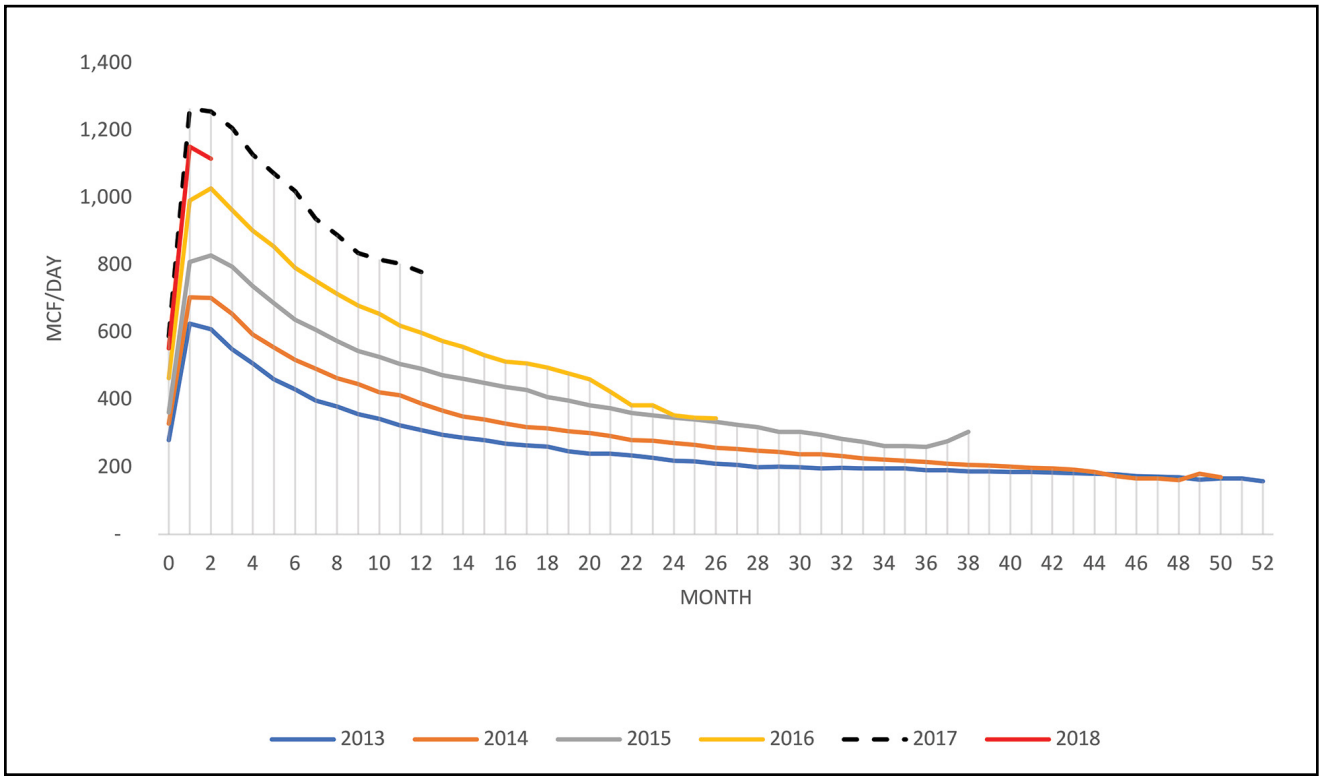
Source: PetroNerds, DrillingInfo

Figure 20
Horizontal Water Decline Curve



Source: PetroNerds, DrillingInfo

Figure 21
Horizontal Gas Decline Curve



Source: PetroNerds, DrillingInfo