May 2018

Permian produced water: slowly extinguishing a roaring basin?

Executive summary

The Permian is comfortably positioned as the most important oil supply growth region today. As operators continue to add rigs and ramp up completions, we expect over 2 million b/d of oil supply growth over the next five years. While attainable, the number of operational risks and bottlenecks continues to grow.

We are expanding our Geology vs. Technology series to include these new risks. After looking deeply at parent-child well relationships and future EUR downgrades, we now switch to produced water. This is a topic being discussed more and more in earnings calls.

Today's growing water situation in the Permian presents a unique set of challenges compared with years prior. The sheer volume of water is unprecedented. Record drilling activity is compounded by more water used in completions and water cuts from the targeted formations rising quickly in older horizontal wells. This latter point is of material concern. In some cases, water-to-oil ratios (WOR) in the Delaware Basin can reach as high as 10:1 and operators are simply unable to cheaply reinject all those volumes.

Water handling is expensive and unit costs are also expected to rise as the simple solutions such as local shallow injection become exhausted. Rising volumes and rising costs are a bad combination that poses an impending supply risk to the overall region.

After modelling numerous scenarios of rising water cuts and growing water management costs – both which seem inevitable today – we project that Midland and Delaware basin sub-play economics could be impaired by US$3 to US$6/bbl. These higher breakevens are enough to result in a nearly 400,000-b/d reduction to our integrated Permian oil supply forecast by 2025. The bulk of the reduction would come from the Delaware Basin.

Managing this risk will require large amounts of capital, particularly in regard to water disposal. Producers need to prepare for these investments and some of the best E&Ps are already doing this, setting the stage for future winners and losers.

Background on Permian water challenges

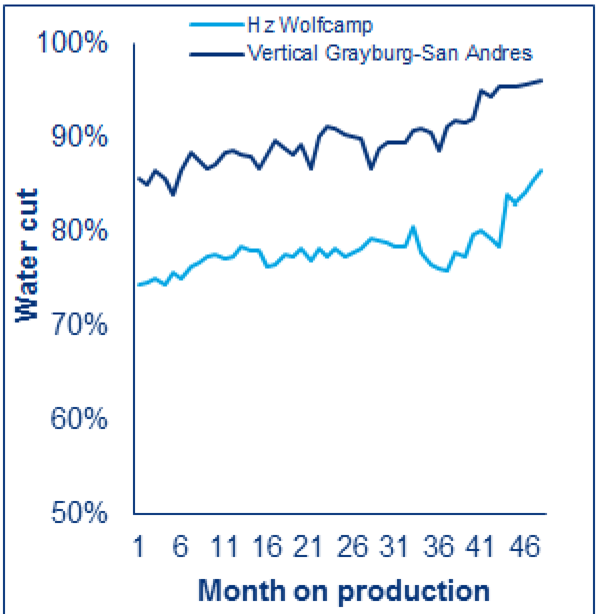
Operators have had to creatively manage produced water in the Permian for decades. The challenge now is that unconventional operations pose a series of different considerations from conventional fields.

- Most of the produced water cannot be reinjected into tight formations for water floods or EOR. In conventional fields, they could. Some Wolfcamp and Bone Spring operators are testing the potential of enhanced recovery techniques, but there are no large-scale applications in place. As a result, produced water must be injected into separate saltwater disposal (SWD) wells, recycled or reused.

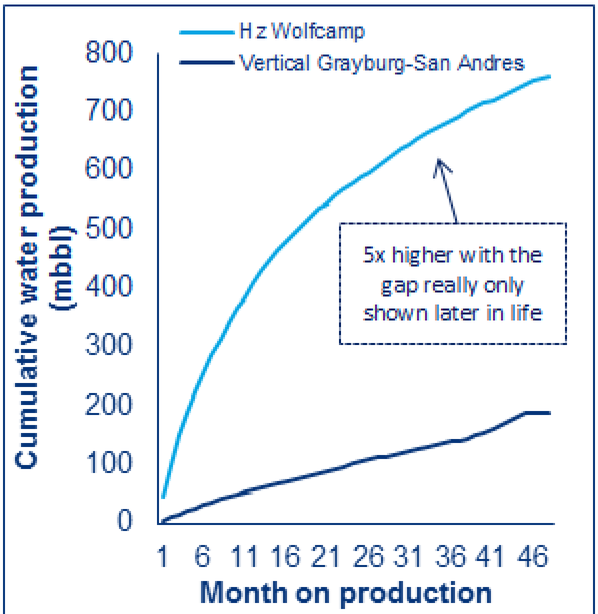
- Water demand continues to increase as operators strive to improve completion efficacy. Volumes pumped per completion are 50% higher than in 2015, close to 17 million gallons of water per current well in the Midland Wolfcamp. This also results in growing volumes flowing back to the surface, because the formation has relatively high water saturation and does not hold fracture fluids.

- Multi-well pad development results in a higher concentration of produced water in a single geography. This puts greater strain on nearby SWD wells and can cause sections of disposal formations to pressure up too fast, limiting the injection rate and causing casing issues in proximal areas of the play.

Water data: Lea County, New Mexico vertical and horizontal wells



Source: Wood Mackenzie North American Well Analysis Tool

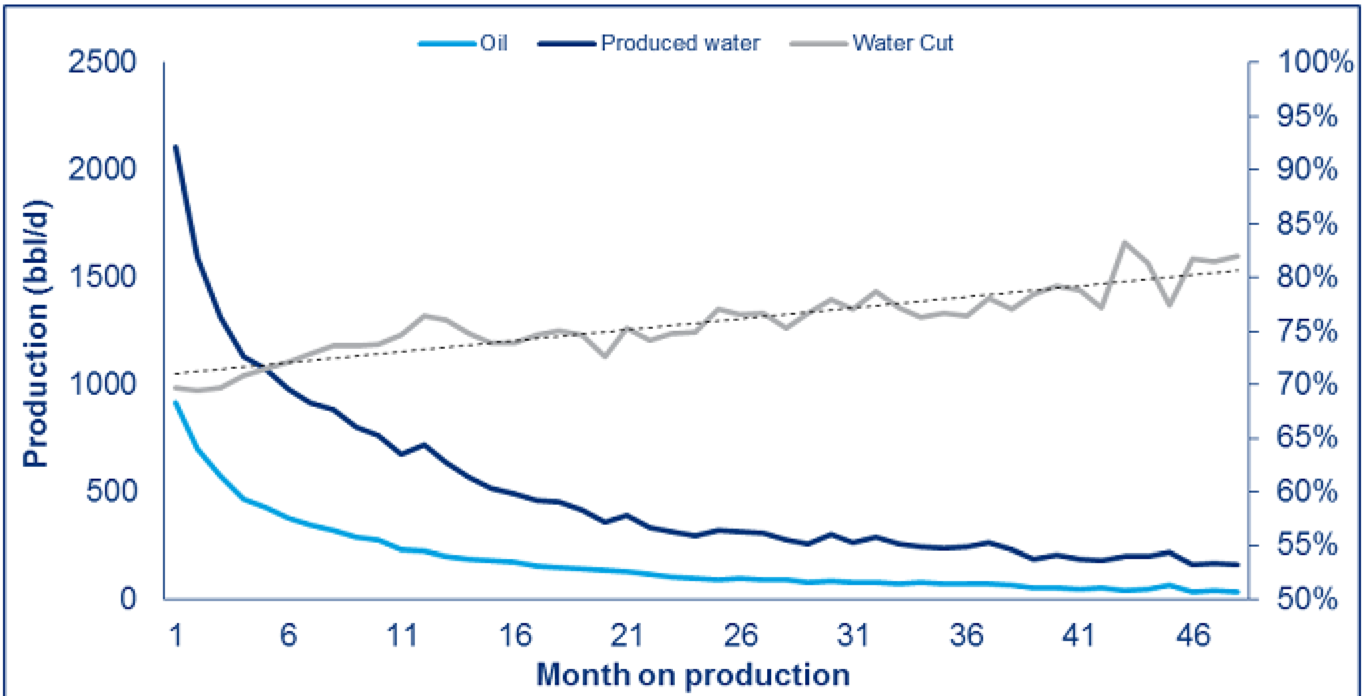


Source: Wood Mackenzie North American Well Analysis Tool

Produced water volumes not only increase throughout the life of the well but also vary considerably depending on the geography and geology of the well. Delaware Basin WORs are often twice as high as in the Midland Basin. Greater formation depth and fractures hitting faults can cause WORs to increase dramatically as well.

For the Wolfcamp formation in the Delaware, the water cut (produced water/[oil + produced water]) has increased from an already high base of approximately 70% to 80% in the first four years of production. An initial WOR of roughly 2:1 can increase to nearly 5:1 by year four and can eventually reach 7:1. The high end of Delaware water cuts can be almost as great as those seen in the Mississippi Lime, with the highest Permian case we found being 10:1.

Average oil and water production for New Mexico Delaware Basin Wolfcamp wells drilled since 2014



Source: Wood Mackenzie North American Well Analysis Tool

Modelling the problem

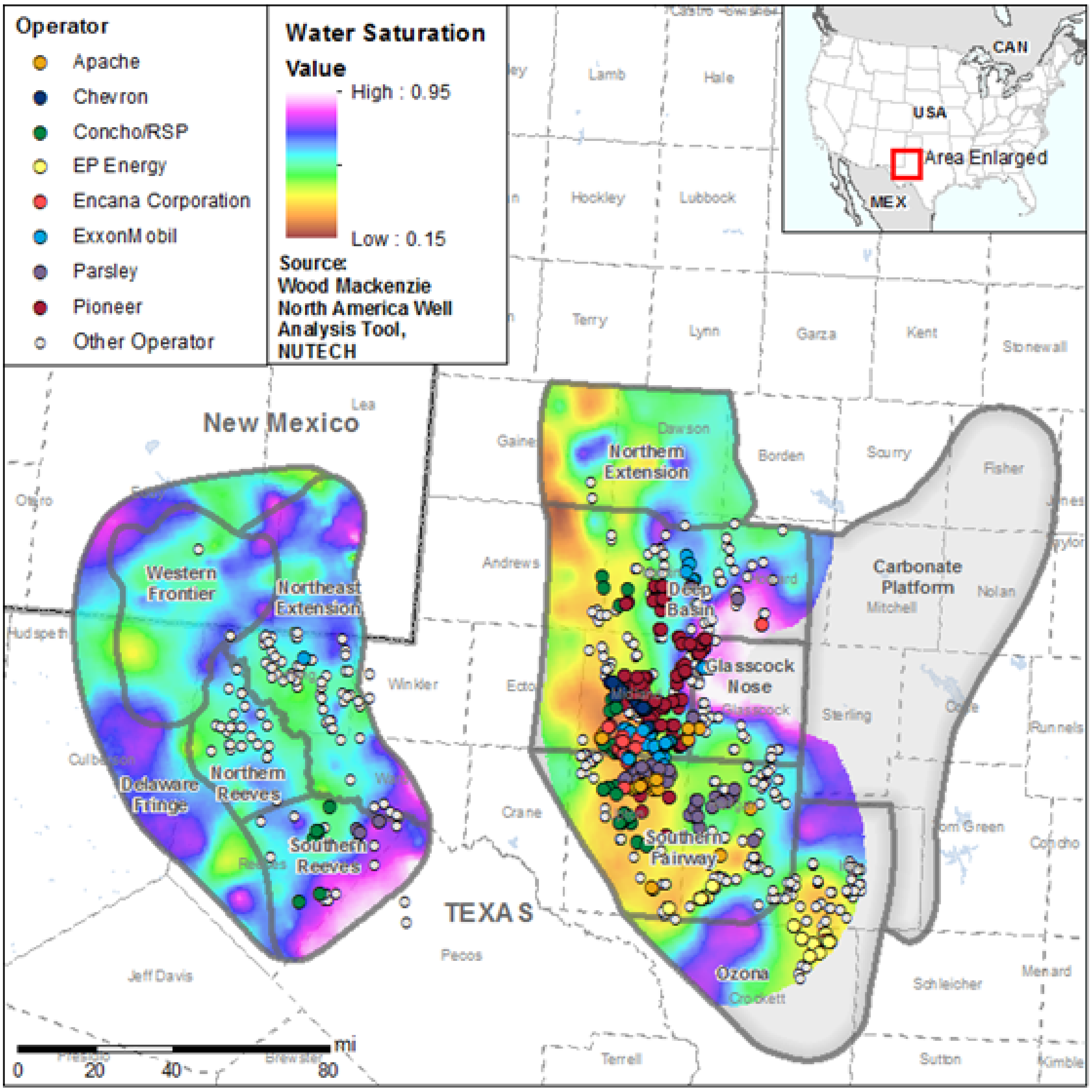
Scenario analysis is required to fully appreciate the risk of rising water volumes. Solutions that work today will not be enough to manage future volumes. Costs will escalate to varying degrees as producers compete for the cheapest solutions.

As a simple illustration, if Permian oil production approaches 6 million b/d by 2025, the average water cut in the region is 4:1, and we assume total water management costs at US$2/bbl. As a result, the annual water-related expenditure in the region could reach US$17 billion, or nearly 20% of total drilling expenditure this year.

The sample set of wells with production histories long enough to see the acute details of how water cuts evolve is limited. Also, state reporting does not include robust datasets for water. As such, we built scenarios to quantify the future risk producers face.

We relied on water saturation data from our subsurface partner NUTECH to help derive multiple water production curves for each sub-play in each basin.

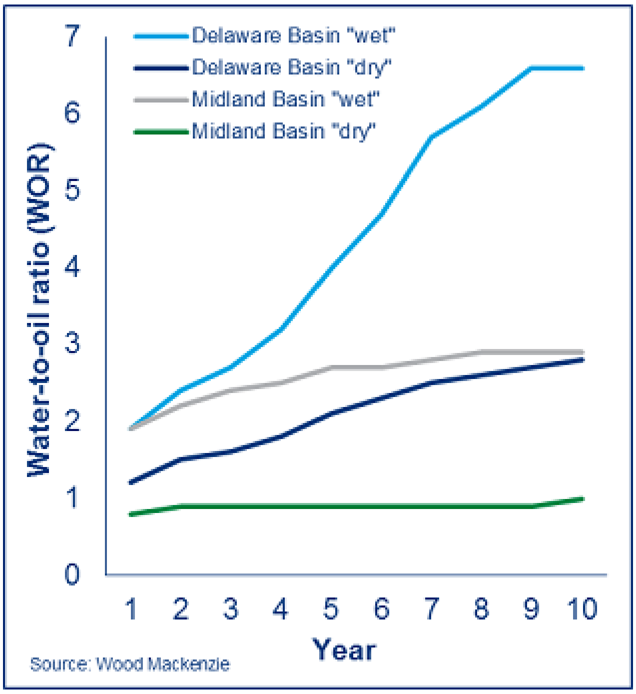
Water saturation in the Delaware and Midland basins for Wolfcamp B bench wells



Wells shown represent Wolfcamp B wells drilled since 2014

Each basin has clear areas of higher and lower saturation, so we applied either a 'wet' or a 'dry' water production curve to that Wolfcamp or Bone Spring sub-play to add more granularity to our models and represent the inevitable variation across acreage.

Water-to-oil ratio assumptions used to generate water curves for Permian sub-plays



Costs to handle the water

The costs associated with water handling are range-bound as well. They sit between US$0.50/bbl to US$3/bbl today, including sourcing, transport, disposal and recycling. Trucking availability and the proximity of a well or pad to existing SWD wells can be the biggest influencing factors.

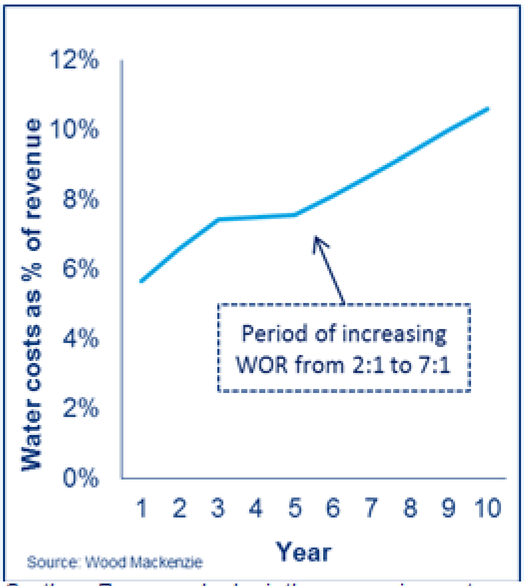
Producers are working hard to keep costs in the lower end of that range. However, early indications from increasing portions of capital budgets being spent on water solutions could be the canary in the coal mine. For example, Pioneer Natural Resources is allocating US$300 million in 2018 for tank batteries and SWD facilities, in addition to new facilities and other expansions for below-grade cellars. Current SWDs cannot handle all the future produced volumes and recycling is not a panacea. The produced volumes are simply too great for all the barrels to be reused in subsequent completions.

Permitting delays have already lengthened from three weeks to nine months and in certain locations, there has been an over-injection of produced water into the San Andres formation. As a result, operators are now looking at drilling an increased proportion of SWD wells in the deeper Ellenburger formation. The increased depth of approximately 14,000 feet and the formation being largely unmapped has resulted in costs of up to US$14 million per well. A growing concern of increased seismicity associated with shallow SWDs across the country and the rapidly increasing cost of road transport both showcase the complexity of the problem. The rate at which water cuts are rising was not anticipated. Similar to midstream infrastructure, the low-cost solutions are exhausted first.

We estimated four cost options that could be applied to the sub-play type well models helping to quantify the long-term economic implications associated with produced water.

Future water cost assumptions and escalating impact plot

Scenario	Midland Basin	Delaware Basin
Aggressive costs	US$1.25/bbl	US$2.00/bbl
Managed costs	US$0.65/bbl	US$1.00/bbl



Data in the chart is representative of the Delaware Wolfcamp Southern Reeves sub-play in the aggressive cost scenario

Three main factors contribute to our 'aggressive' future cost scenario.

1. The majority of Delaware Basin produced water could rely heavily on trucking into the future because the regulatory climate is more challenging in New Mexico and policies are more stringent. Also, Delaware Basin water is harder and modifying pH for recycling is expensive.

2. The number of new SWD wells could be limited. There are two disposal zones in the Midland Basin – the shallower San Andres and the Ellenburger, which is roughly twice as deep. There are two disposal zones in the Delaware – the Mountain Group and the deeper Ellenburger. However, in the Delaware, the Ellenburger is twice as deep as it is in Midland and four times deeper than the Mountain Group. The cost to tap the Delaware Ellenburger will slow the growth of deeper injection options there.

3. The Midland Basin already relies less on trucking and cost-reduction initiatives are further de-risked than in the Delaware. For example, Pioneer Natural Resources entered into a unique agreement with the city of Midland in Texas to help reduce overall water management costs through more cost-effective sourcing by investing in the improvement of water pollution and control plants in addition to purchasing reclaimed water. However, that is one example and still doesn't address that water cuts are still rising in the Midland as well. Future volumes will outstrip the capacity of current options.

In the more benign 'managed' costs scenario, we assume a big uptick in reuse. We also considered the option that produced water is transported via pipeline in the Midland Basin.

Translating water risks into macro takeaways

We modelled all these future potential water costs as part of our type curve analysis.

Under all the elevated future cost scenarios, no sub-play type wells became uneconomic. Higher water volumes and higher costs did not shorten the economic life of our type wells either. This is largely because of our long-term WTI price outlook.

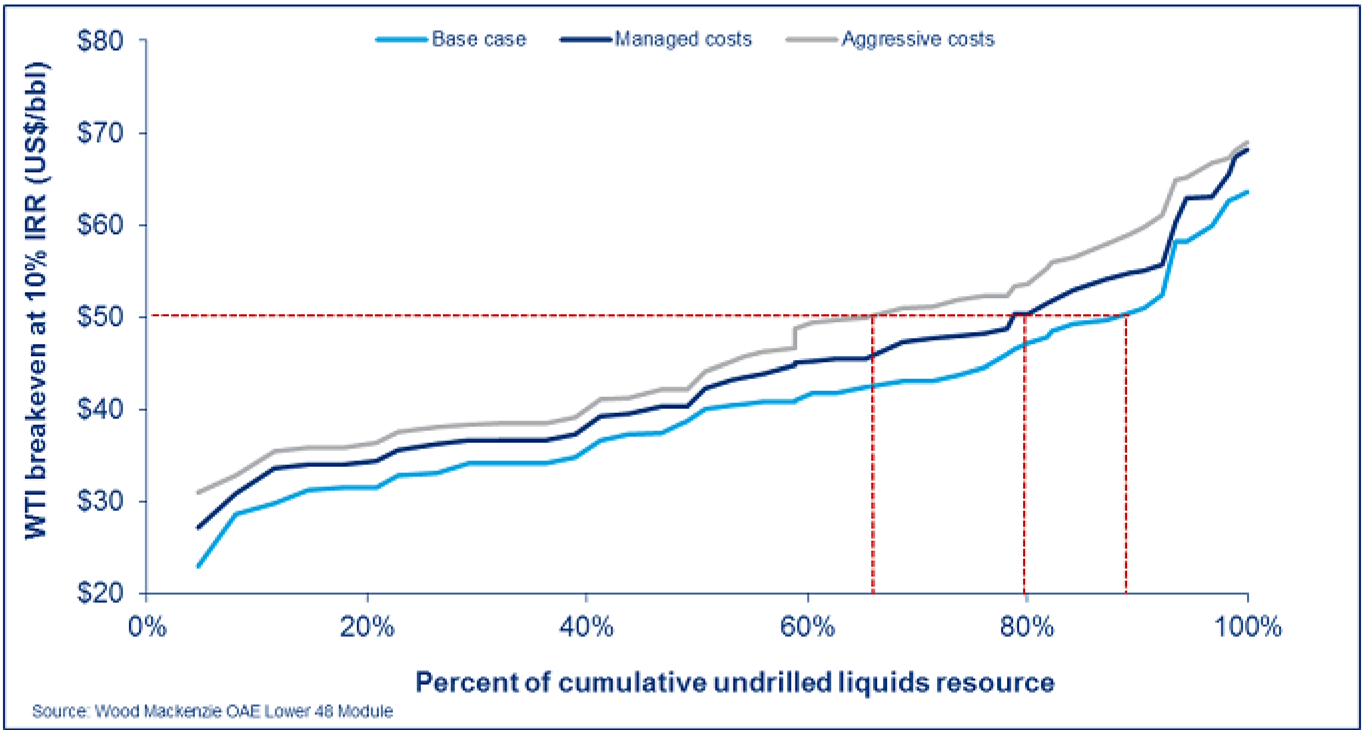
However, our investigation of single well water risks quickly scales up to a material impact when we study the combined impact rising water volumes and increasing water costs have on future breakevens for undrilled wells deep into companies' inventories.

These metrics increased on average by US$6/bbl in the aggressive cost scenario compared with our base case that utilises water cuts seen today, as well as current lease operating expenses (LOE) to handle produced water. To put that magnitude of increase into perspective, 25% lower productivity or a 20% increase in D&C costs is needed to realise a similar increase in breakevens. The managed cost scenario resulted in a breakeven change about half as large, and variations were clearly seen at the sub-play level.

Production growth impact

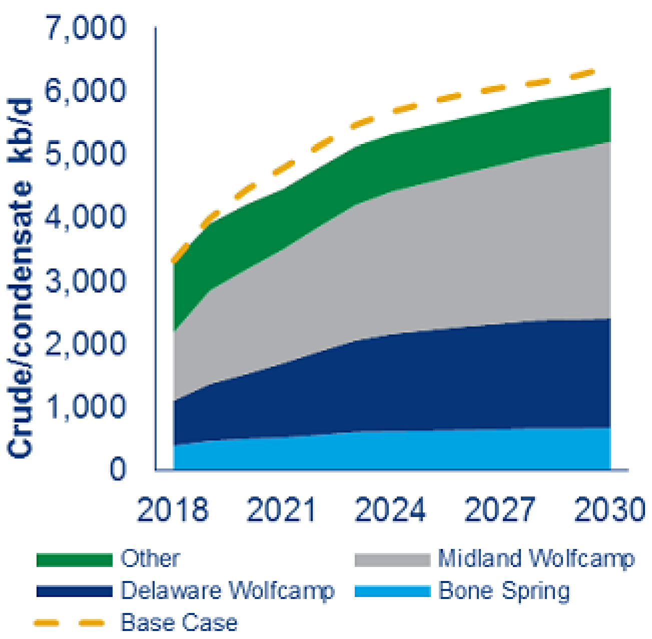
When the updated PV10 breakevens were incorporated into Wood Mackenzie's dynamic long-term oil price model, the resulting oil outlook to 2025 was nearly 400,000 b/d lower than the reference case using today's water data.

Permian tight oil cost curve comparison: two water scenarios

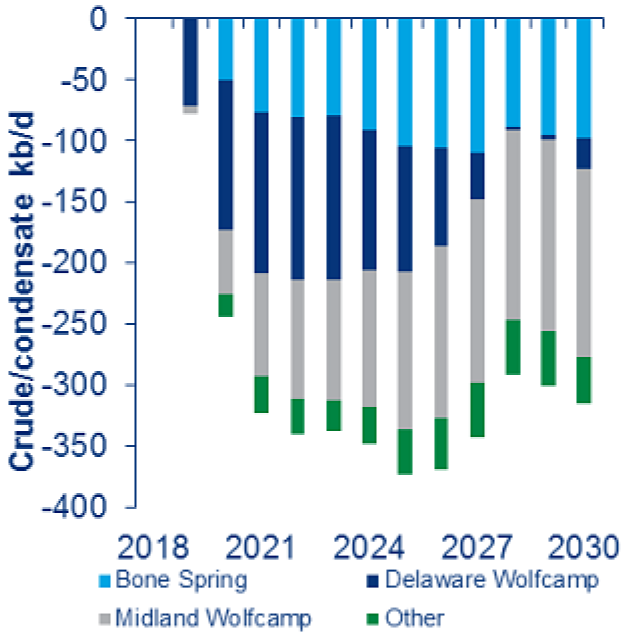


Under the aggressive cost scenario, annual production growth is 15% slower through 2025 than the base case. The Delaware Basin is responsible for roughly 65% of the supply reduction due to the higher water costs and water cuts. The Midland Wolfcamp was still impacted by roughly 150,000 b/d though.

Permian oil supply outlook under aggressive water cost scenario



Source: Wood Mackenzie OAE Lower 48 Module



Source: Wood Mackenzie OAE Lower 48 Module

Combating the challenge

Early water planning was difficult because the location of the most densely developed Permian acreage was not completely known. Now it is, so some operators – likely the later entrants with more remote acreage – will need to play catch-up with appropriately managing water-related risk. The opportunities in this space can clearly be seen through the gap between the managed and aggressive cost scenarios.

One of the best opportunities for operators to reduce water costs is by investing in pipeline infrastructure, limiting the amount of trucking and collaborating with offset operators. For example, Laredo Petroleum has been gathering increasing volumes of produced water by pipeline in addition to other water infrastructure investments and was able to reduce its 2017 LOE by more than US$10 million. Relying heavily on trucking can result in an incremental US$1 to US$1.25/bbl with virtually certain future price increases as trucking regulations become stricter, pads become more remote, and roads become more congested.

Recycling cannot solve all the problems though, but it can provide massive support over the next few years. Operators such as Callon Petroleum have recently mentioned sourcing 50% of water volumes from recycling for certain Delaware Basin drilling pads with no impairment to well productivity. This is a big positive.

We expect to see the proportion of recycled water volumes continue to increase as more operators understand how to best manage chemistry and use the volumes in new, offset completions. Potential savings range from US$1 to US$2.50/bbl in total LOE. Cimarex for example recently mentioned saving US$1.10/bbl from recycling produced water for completions operations. The company could realise an approximate US$500,000 cost savings per well if we assume a 10,000 ft. lateral completed with 2,000 gallons of water/ft. Recycling also decreases the reliance on SWD wells, which would postpone the need to permit and drill Ellenburger injection wells instead. Furthermore, there are increasing questions regarding whether water could ultimately become a revenue source for operators. Produced waters are expected to far exceed the demand for hydraulic fracturing so opportunities may exist for the sale of recycled water to agriculture for example.

Expect producers to invest more in water management solutions, and if budgets stay relatively flat the next few years, watch drilling capital be diverted to water-related investments. Just as the level of drilling intensity in the Permian breaks basin records, so should the scale of water management solutions.

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