KIMMERIDGE Energy

The Best of the Best

Why the Delaware Basin Ranks Top amongst US Tight Oil Plays

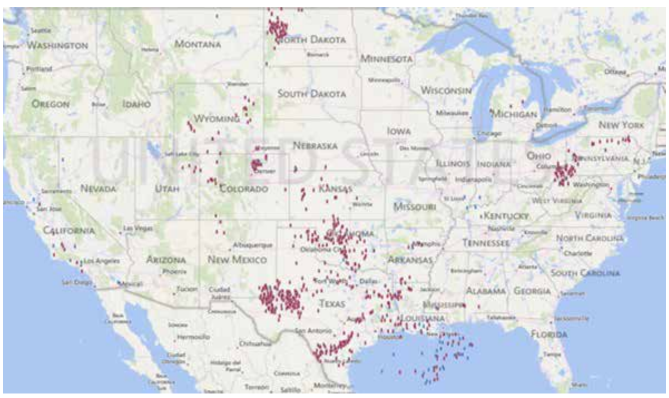
September 2015

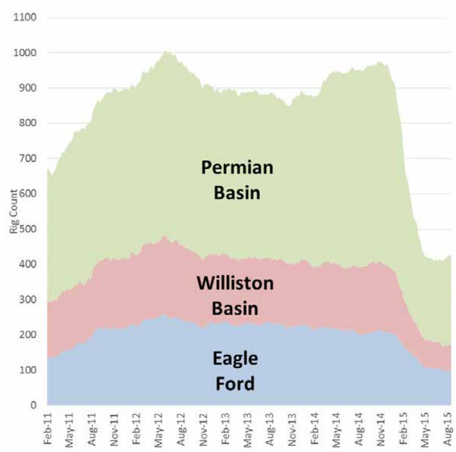
Introduction

The surge in US oil production over the past few years has resulted from the exploitation of tight reservoirs using modern completion methods, such as extended laterals with multi-stage hydraulic fracturing. The first tight oil play where these completion methods were used was the Bakken, which kicked off in 2005. The Eagle Ford followed in 2009, and since then, US companies have searched across the country for the "next Bakken or Eagle Ford", leading to plays like the Niobrara, Woodford, Utica and Wolfcamp.

Many of these plays are at relatively mature stages, with thousands of development wells and detailed understanding of the geology, making them useful analogs when looking at emerging tight oil plays or extensions of existing plays.

A map of active rigs in the US shows onshore drilling activity in North Dakota, West Texas (Permian), South Texas (Eagle Ford), Oklahoma (Woodford), Colorado (Niobrara) and Ohio (Utica). However, approximately 50% of all active onshore US rigs are focused on just three of these areas: the Permian Basin, Williston Basin and Eagle Ford *(Exhibits 1 & 2).*





Exhibits 1 & 2: Map of US rig count – Aug 2015 (DrillingInfo); Chart of rigs in three main tight oil plays (BakerHughes)

The precipitous decline in oil prices this year has resulted in a sharp drop in drilling activity, with the US rig count bottoming in June and rebounding slowly since then. Interestingly, the rebound has not been even, with the Permian seeing an increase of 22 rigs from its low, but only one incremental rig added in the Eagle Ford and four in the Williston Basin.

Additionally, based on companies' presentations, as well as recent M&A activity, it is clear that drilling capex is being reallocated to the Permian, and in particular the Delaware Basin, which is gaining recognition as being at the very front end of the US cost curve. Indeed, recent research by Goldman Sachs states that the Permian Basin (and specifically the Delaware Sub-Basin) has the lowest break-even cost of all tight oil plays, beating out more mature plays such as the Bakken and Eagle Ford *(Exhibit 3).*

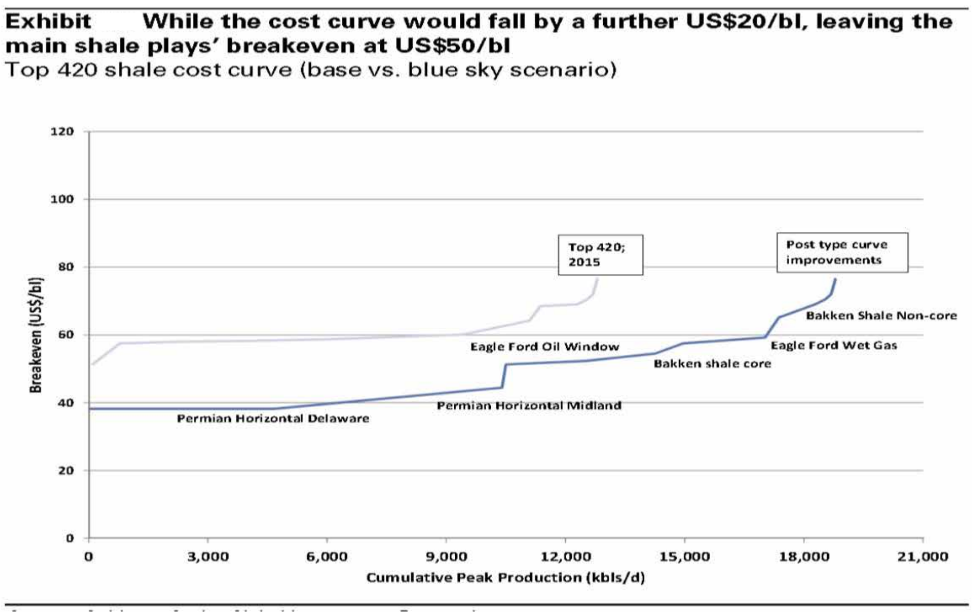


Exhibit 3: US shale cost curve (Goldman Sachs Research)

While cost curves offer an approximation of the relative performance of shale plays, they rely on inherently subjective assumptions, and they treat each play uniformly without recognizing internal variability. Instead, a more statistical analysis needs to be developed. When evaluating new unconventional plays, the Kimmeridge team has in prior research highlighted the fact that each play can be evaluated based on NPV/well, repeatability and areal extent. For example, if one play generates a NPV of $3 million per well drilled, has 100% repeatability and covers 16,000 net acres, then with 160-acre spacing, you have 1,000 locations and $3 billion of value. In contrast, a play with a NPV per well of $2 million and 50% repeatability over the same area only offers $1 billion of value.

The value of acreage:

NPV10/well x Repeatability x Areal extent = Potential Value

Areal extent is easy to measure. However NPV is not, given the variability in well costs and lack of company disclosure on a well-by-well basis. While not perfect, a proxy for NPV/well that can be uniformly measured is 30-day initial production (IP) per 1,000 lateral feet. This leaves us with repeatability. Using the Fayetteville as a test case, we analyzed the standard deviation of IP per 1,000 lateral feet between different operators and created a Repeatability Index (0-100%) based on the Coefficient of Variation (CV = Standard Deviation / Mean), with higher CV indicating low repeatability and lower CV indicating high repeatability.

This analysis is highly valuable. In theory, every acre acquired involves a trade-off of moving away from a proven well, and thus increasing the repeatability risk. The further you step away, the greater the risk becomes. Large acreage packages may be attractive and available, but if this increases the coefficient of variation, they are less attractive. By analyzing historical plays we can frame the increase in this risk by distance, while ranking the core of one play against the fringe of another. Moreover, using our understanding of each play's geology and examining well performance versus completion method for over 25,000 horizontal wells, we have attempted to determine which of the various US tight oil plays ranks best, and within those, which counties rank highest.

Comparing the Top Three US Tight Oil Plays

For a detailed review of the geology in these plays and our methodology for identifying the geologic core areas, please reference the Appendix.

(1) Bakken and Three Forks

The Bakken is the most mature tight oil play in the US, with appraisal drilling starting in 2005 and full field development beginning in 2007/8. Kimmeridge has assembled a dataset of around 10,000 wells with initial production data and completion data, such as lateral length (gross perf interval), frac stages, proppant amount and frac fluid amount. Around 7,300 wells were completed in the Bakken formation and roughly 2,700 in the Three Forks formation. We have mapped this well performance and completion data across the basin for both plays, to derive IP/1000' of lateral contour maps, which indicate the core of the plays based on well data *(Exhibits 4 & 5)*. This is compared to the red outline of the geologically-derived core (based on geochemical and geological data). Note that the geologic core for the Three Forks is the same as the Bakken, since the main constraining factor for the Three Forks play is oil charge from the Lower Bakken shale.

Overall, there is a good overlap between the geologic core and the best well results based on IP per 1,000' of lateral for both the Bakken and Three Forks plays. However, the best area (based on this metric) in the Bakken play is the Parshall oil field, which sits just outside of the core area. Parshall is a pseudo-conventional oil field where oil has migrated laterally updip from the Bakken source kitchen, but stayed within the Middle Bakken reservoir. Additionally, it is dominated by a single operator, EOG, which is arguably the best in the play, with the highest average IP/1,000' of lateral and good repeatability of completions (low CV) versus other operators *(Exhibit 6).*

Indeed, within the Bakken play, there appears to be a trade-off between well performance and repeatability of completions, with companies such as QEP, Brigham (acquired by Statoil in 2011) and Petro-Hunt having some of the best average well performance, but considerable variability in their well results, indicating low repeatability of completions. On the other end of the spectrum are companies such as OXY, Marathon, XTO and Statoil, with very repeatable completions, but relatively low mean IP/1,000'.

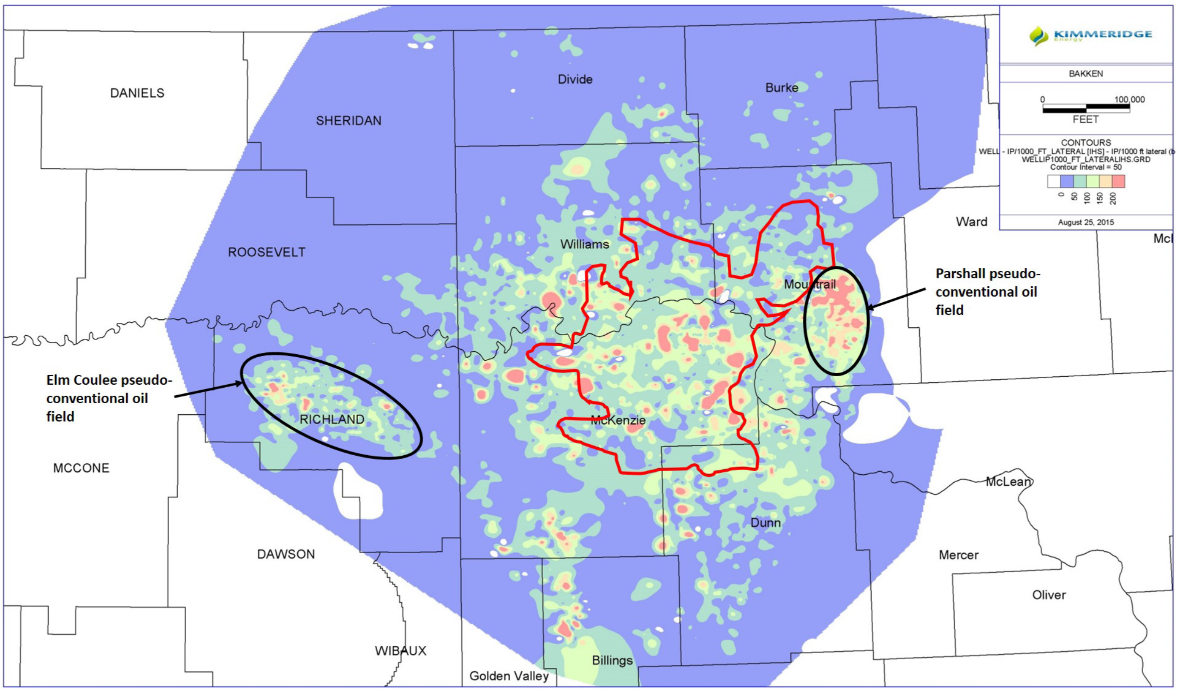


Exhibit 4: Bakken 30-day IP/1,000' of lateral with geologic core overlaid in red (IHS, NDGS and Kimmeridge estimates)

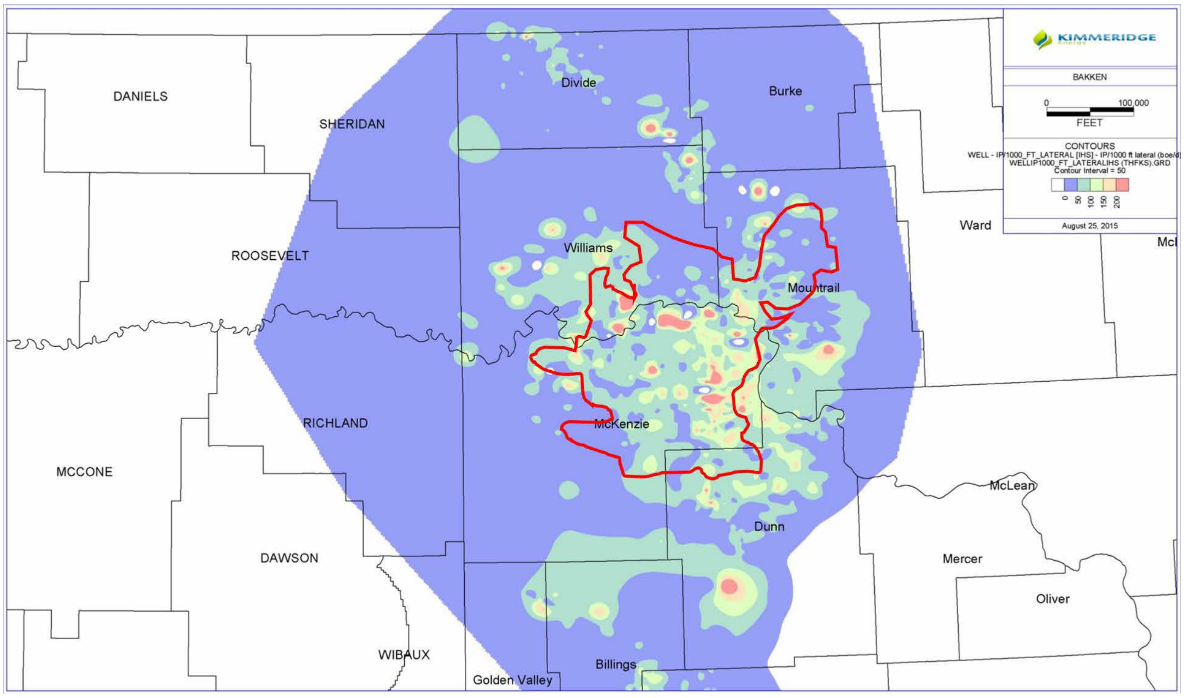


Exhibit 5: Three Forks 30-day IP/1,000' of lateral with geologic core overlaid in red (IHS, NDGS and Kimmeridge estimates)

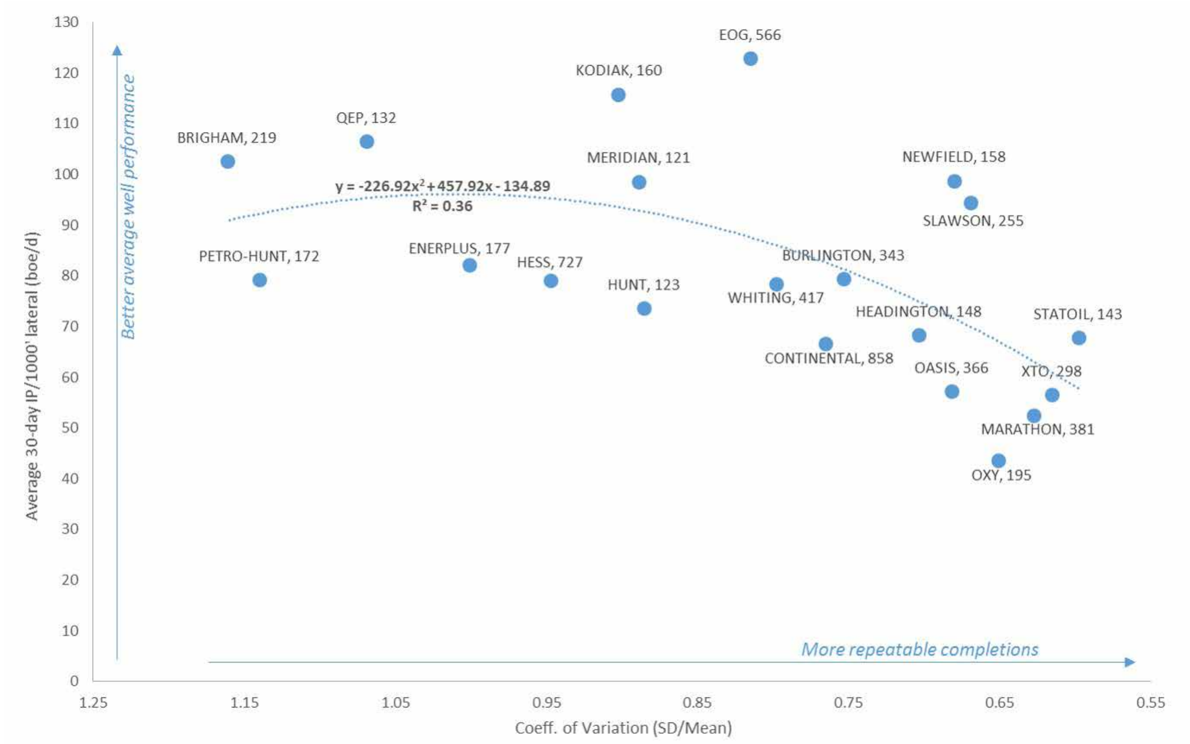


Exhibit 6: Bakken 30-day IP/1000' of lateral by operator with well count (IHS, NDGS and Kimmeridge estimates)

(2) Eagle Ford

The Eagle Ford was the second major tight oil/liquids play in the US after the Bakken, emerging around 2009 and entering full field development in 2011. We have assembled a dataset of around 7,000 wells with 30-day IP and lateral length data (estimated from surface location and bottom hole location), and mapped this across the play to indicate core areas based on normalized well performance *(Exhibit 7).*

Based on our knowledge of the play, we know that the most economic parts of the Eagle Ford are in the late oil-to-condensate windows where there is the right combination of high liquids content and overpressure. Overlaying these thermal maturity windows against a map of IP per 1,000' of lateral confirms this thesis. The gas window is relatively undrilled due to the high costs of drilling at significant depths and low returns at current gas prices.

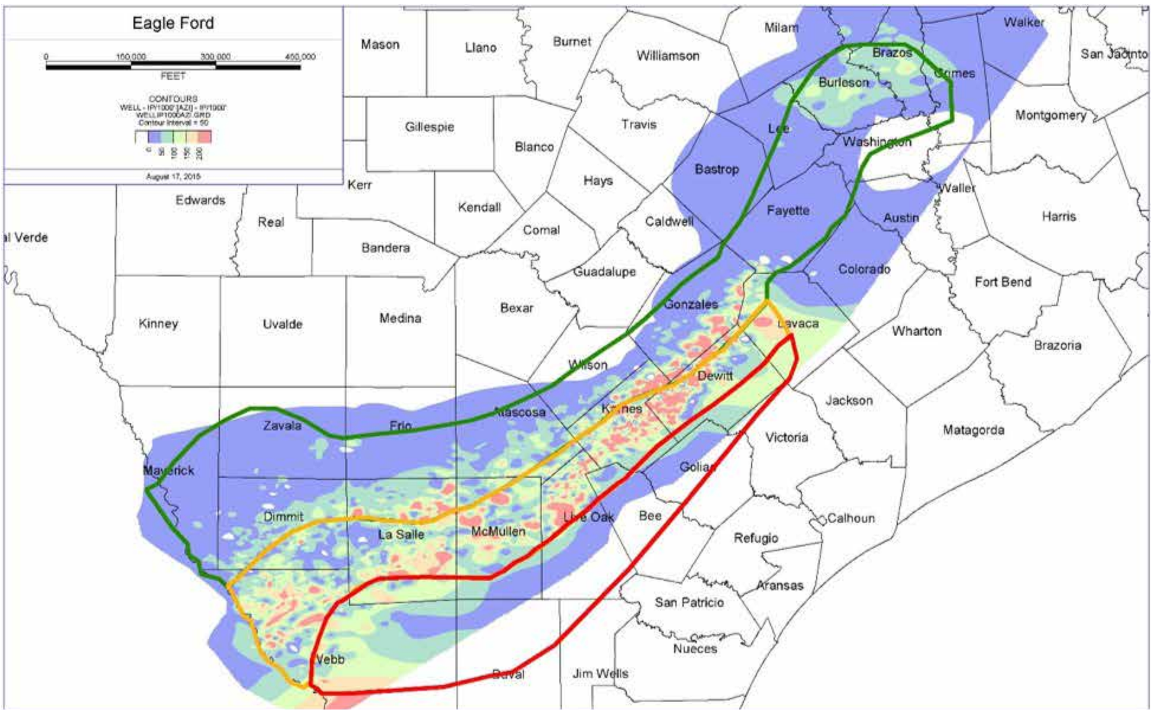


Exhibit 7: Eagle Ford 30-day IP/1,000' of lateral with oil (green), condensate (orange) and gas (red) windows overlaid (EIA, Drilling Info and Kimmeridge estimates)

Looking at the various operators within the play, Devon and Pioneer appear to screen best, with the highest average IP/1,000' and good repeatability of wells *(Exhibit 8).*

Interestingly, EOG has the third highest average well performance, but a high degree of variability in well results, indicating low completions repeatability. Digging into the data for EOG shows that the variability is likely driven by geology (not operator performance), with their acreage in La Salle, McMullen, Karnes and Gonzales Counties showing consistently good well performance, but their acreage in Atascosa having significantly lower results.

We should note that the Eagle Ford play does have the potential for multiple stacked producing wells, with companies initially developing the Lower Eagle Ford, but more recently appraising the Upper Eagle Ford with encouraging results, although it does not appear to be as economic as the Lower Eagle Ford. Indeed, at lower oil prices in 2015, companies such as Penn Virginia, which was drilling the Upper Eagle Ford in Gonzales County, have discontinued these drilling programs to refocus on the Lower Eagle Ford. Specifically, Penn Virginia's average IP from 10 Upper Eagle Ford wells was 618 boepd compared to 1,027 boepd for 10 wells completed in the Lower Eagle Ford during the same period using similar sized completions. Given the roughly equal drilling and completion costs, but 40% higher IP rate, this suggests that the Lower Eagle Ford is significantly more economic, especially at current commodity prices.

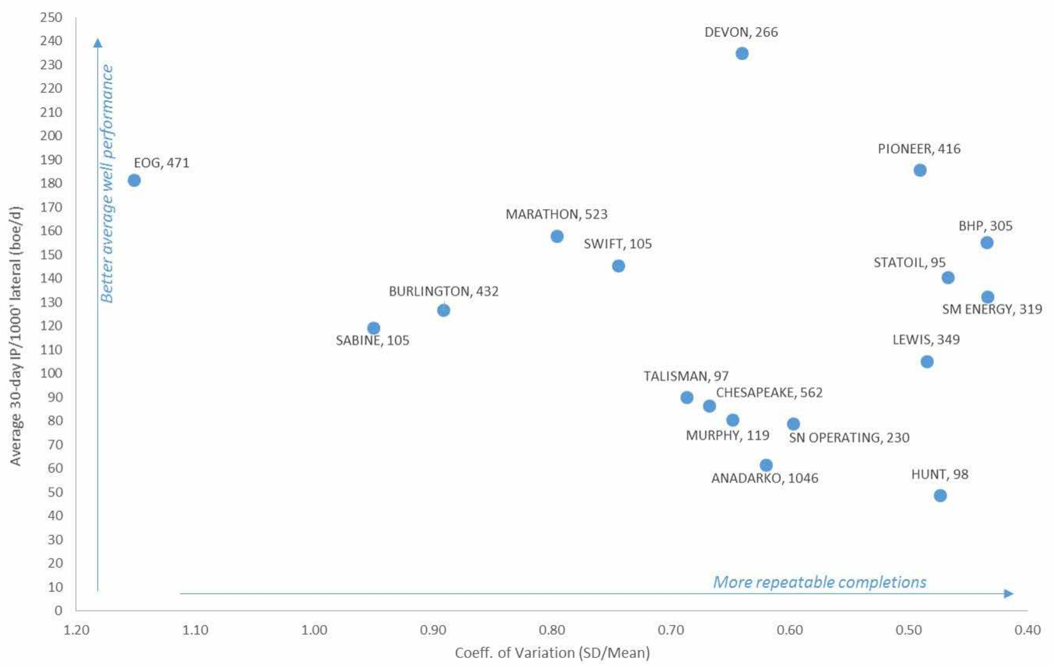


Exhibit 8: Eagle Ford 30-day IP/1,000' of lateral versus coefficient of variation by operator (EIA, Drilling Info and Kimmeridge estimates)

(3) Permian Basin

The Permian Basin resource plays date back many decades if you include the Spraberry field which was discovered in 1943, with very low recovery rates of around 10% prior to 2005. The play has since seen a large increase in production due to the application initially of fractured vertical wells, and more recently, fractured horizontals. Additionally, the entire basin has seen increased production as a result of modern completion methods applied to new reservoirs such as the Wolfcamp, Bone Spring, Avalon and Cline.

The Midland side of the basin is arguably more mature, in terms of industry activity, production and acreage pricing. However, the Delaware side of the basin has seen more horizontal wells drilled. Overall, the Permian Basin saw significant horizontal drilling from around 2010 onwards, following on from the Bakken and Eagle Ford plays.

In the Permian Basin, Kimmeridge has collected a dataset of >6,600 horizontal wells with completion and well performance data, including 4,000 wells on the Delaware side and 2,600 on the Midland side. Kimmeridge is also an active participant in the Delaware Basin through its investment in Arris Petroleum, with wells drilled in both Culberson and Reeves Counties in West Texas. Notably, well performance on the Delaware side has measurably exceeded that of the Midland side. Based on 30-day IP/1,000' of lateral, many horizontal wells have exceeded 200 boepd/1,000' (red areas in map) on the Delaware side, while very few have matched such performance on the Midland side *(Exhibit 9).*

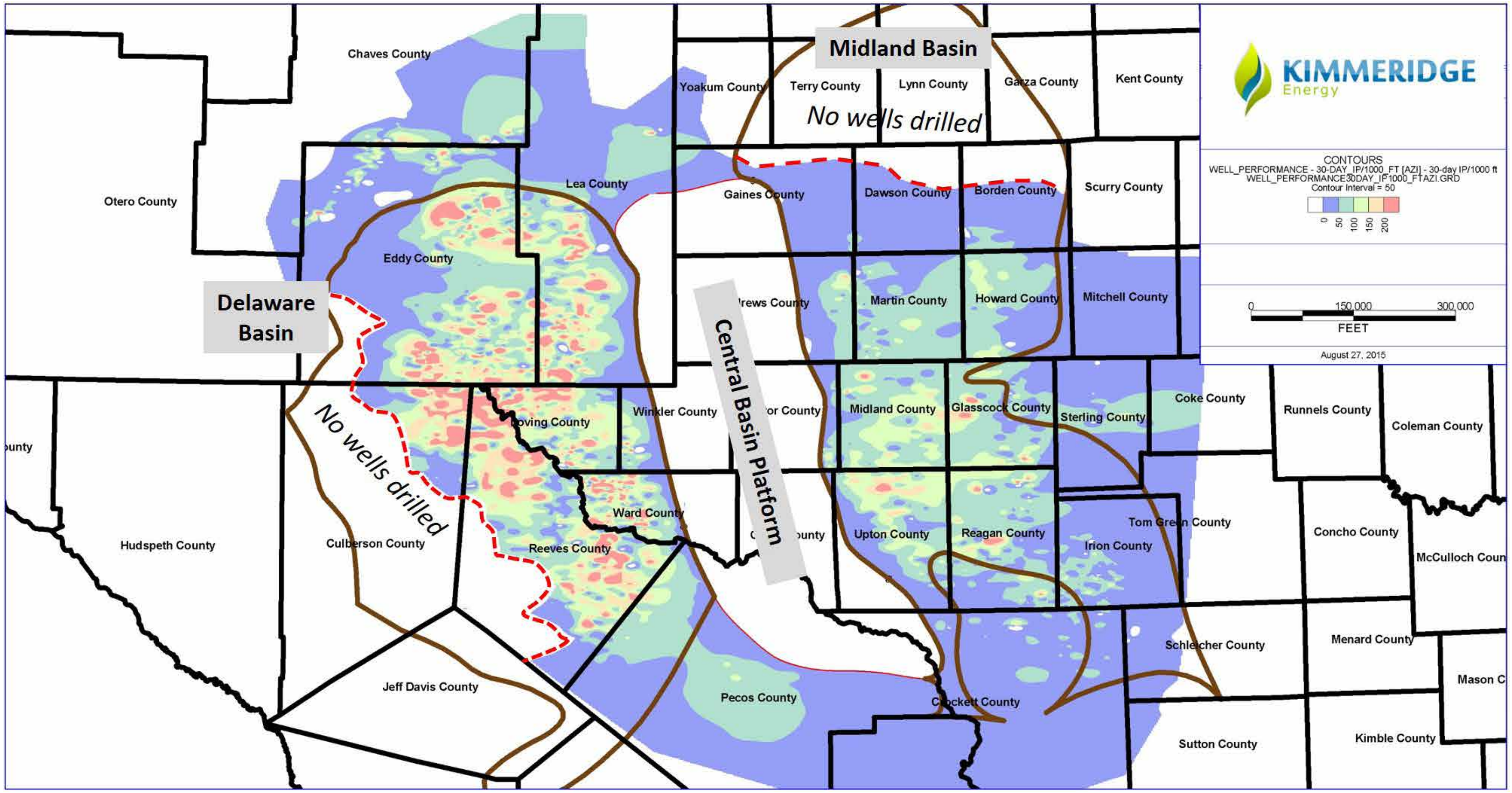


Exhibit 9: Permian Basin 30-day IP/1,000' of lateral (IHS and Kimmeridge estimates)

Looking at the largest operators in these plays, it is clear that Delaware Basin operators are consistently outperforming Midland Basin operators. Indeed, the range in completions repeatability is roughly the same for both basins, but the average well performance is consistently higher in the Delaware *(Exhibit 10)*.

We believe that this is driven by superior geology on the Delaware side, rather than variability in operator performance. As evidence, companies such as EOG and Energen operate in both basins, and both have better average performance on their Delaware Basin wells.

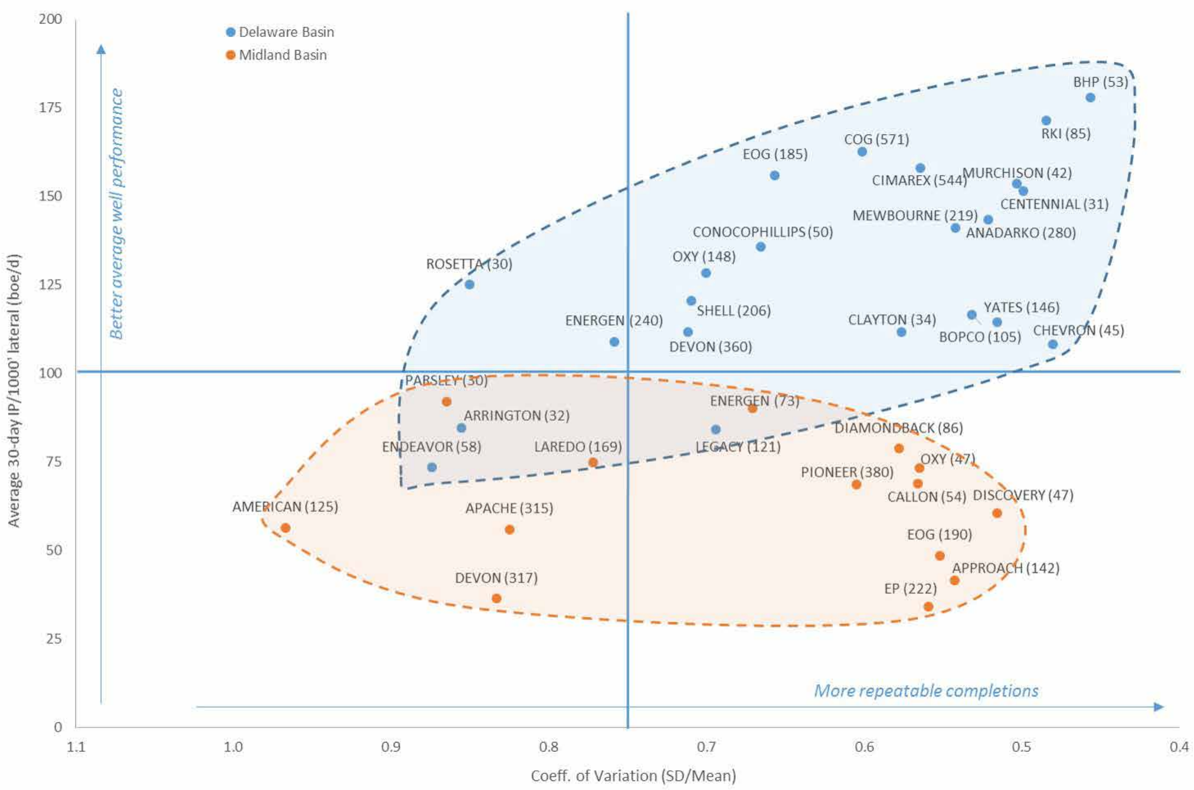
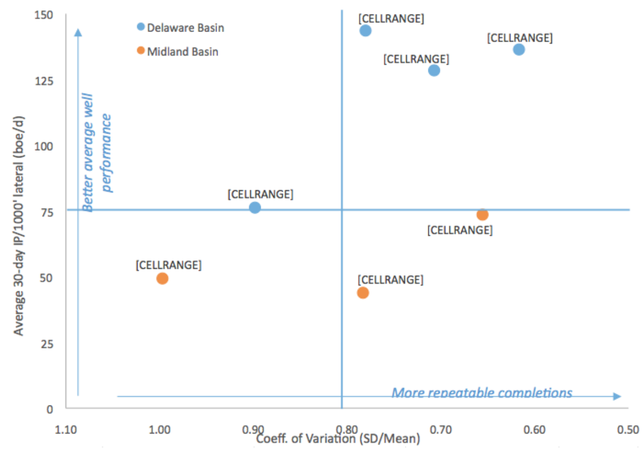


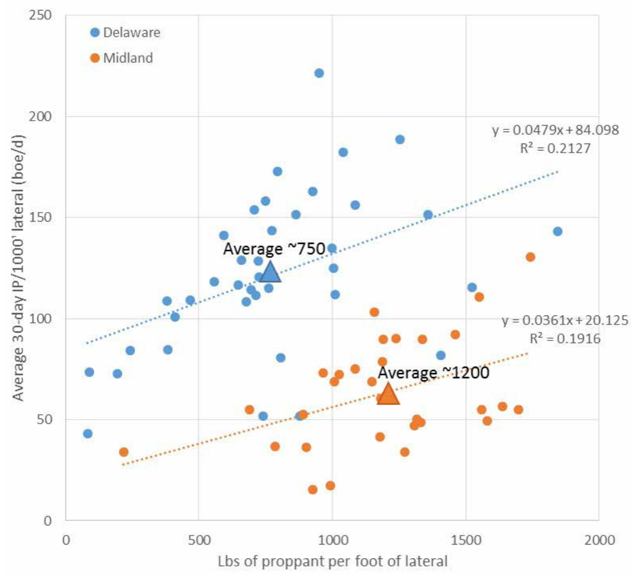
Exhibit 10: Permian Basin 30-day IP/1,000' of lateral versus coefficient of variation (IHS and Kimmeridge estimates)

Another completion metric to consider other than lateral length, is proppant per foot of lateral – or the intensity of the completion versus IP/1,000' of lateral. Using a dataset of around 6,400 wells, we can see that in both the Delaware and Midland Basins, operators are using between 250-1,750 lbs of proppant per lateral foot. However, Delaware Basin well performance is consistently higher across operators, and interestingly, the average amount of proppant per foot used on the Midland side is higher at around 1,200 lbs/ft versus only 750 lbs/ft on the Delaware side *(Exhibit 11)*. This suggests room to increase completion intensity in the Delaware Basin to further enhance well performance.

Another factor to consider is the various plays within each basin, since the geology is variable and therefore directly affects both completion design and well performance. Within the Delaware Basin, most completions in our dataset (>2,400) have been in the Bone Spring formation, which has the most repeatable completions and also the highest average IP/1,000' *(Exhibit 12)*. We can note that the Wolfcamp formation, albeit lower, has similar well performance and repeatability for a smaller sample set of approximately 1,400 wells. We believe that results for the Wolfcamp will continue to improve as operators understand the play better and focus on the optimal landing zones. To date, many operators have drilled the Lower Wolfcamp, which is the gassiest part of the formation, in order to hold leases by production (HBP) to the formation's deepest depth. These wells have likely been uneconomic at current gas prices and designed to hold acreage, rather than optimize well performance. However, the Upper Wolfcamp has more oil than the Lower Wolfcamp, making it a more economic target once leases have been held by production and development drilling occurs.

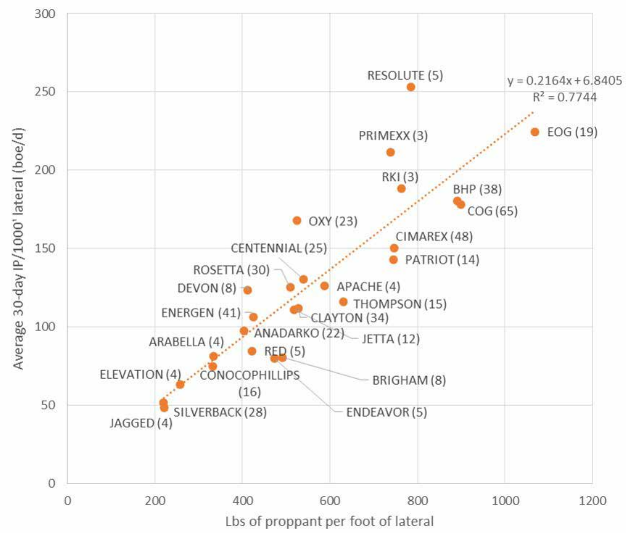
On the Midland side, the Spraberry formation has the best well results and repeatability based on ~1,200 wells, while the Wolfcamp has significantly lower well performance and repeatability.

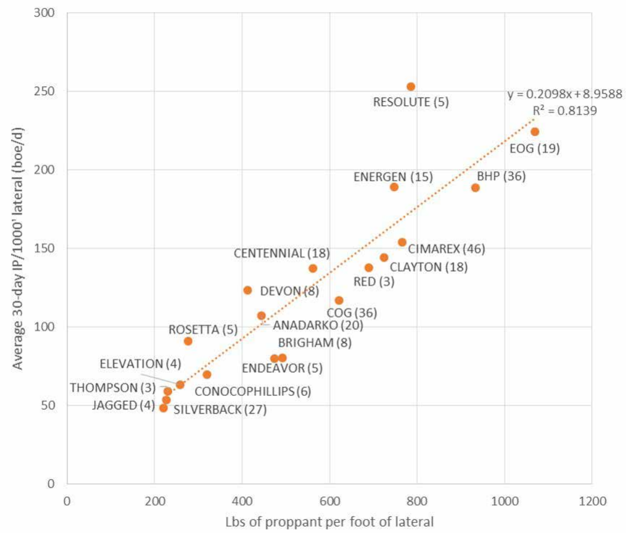




Exhibits 11 & 12: 30-day IP/1,000' vs. lbs of proppant/ft by operator; 30-day IP/1,000' vs. coefficient of variation by producing formation (IHS, DrillingInfo and Kimmeridge estimates)

The data can be sub-divided further, by isolating operators within a single county such as Reeves, one of the core areas of the Delaware Basin, where we believe the geology is reasonably consistent across the county. In this instance, most of the variability in well performance can be explained by differences in completion style for various operators – specifically, there is a strong correlation between IP/1,000' and lbs of proppant/ft *(Exhibit 13)*. Taking this a step further, we can take only Wolfcamp wells for operators in Reeves County, which increases the strength of the correlation to >80%, and isolates the impact of completion intensity on well performance *(Exhibit 14)*. Based on this analysis, it becomes clear that the best operators in Reeves are those with the most intense completions.





Exhibits 13 & 14: 30-day IP/1,000' vs. lbs of proppant/ft by operator for Reeves County; 30-day IP/1,000' vs. lbs of proppant/ft by operator for Reeves County Wolfcamp wells only (IHS, DrillingInfo and Kimmeridge estimates)

Comparing the Top Three Tight Oil Plays

If we define "core" areas of the top three tight oil plays as those with well performance greater than 100 boepd per 1,000' of lateral, we can measure the areal extent of these core areas, giving us an idea about the relative scale and quality of each play *(Exhibit 15).*

The Delaware Basin has the largest core area, and we believe this will continue to expand as companies appraise the play and test new areas. The Delaware is the most recently developed of these big plays, so the areal extent is likely to change more than the others (with the exception of the Three Forks), which all have been well-delineated.

Interestingly, the Bakken has a relatively small areal extent of core acreage, based on this metric, and the Three Forks is much smaller, although the play is further behind in its development than the Bakken. The Eagle Ford has the second largest core area at 2.6 million acres, while the Midland Basin has the second smallest core area at 0.8 million acres.

While areal extent gives us a rough idea of the relative scale of these plays, a crucial element we have not considered is prospective thickness and ultimately the number of stacked producing intervals. While the Williston Basin has two target intervals in the Middle Bakken and Upper Three Forks, and the Eagle Ford also has two in the Lower Eagle Ford and Upper Eagle Ford, the Permian Basin plays have the potential for several stacked productive intervals.

On the Midland side there are multiple targets. In stratigraphic sequence, these include the Spraberry, Upper Wolfcamp, Middle Wolfcamp, Lower Wolfcamp and Cline. While on the Delaware side there is the Avalon shale, three benches in the Bone Springs, and three benches in the Wolfcamp, the various intervals are not present throughout. Nevertheless, in areas of the Permian Basin there are potentially 3-5 stacked productive intervals that are economic even at lower oil prices, versus only two in the Bakken/ Three Forks and Eagle Ford plays. Consequently, of the top three largest tight oil plays we believe that the Permian Basin ranks highest and within the Permian, the Delaware side of the basin has seen superior well performance.

Play/Basin	Core Area (Million Acres)	Core Counties
Delaware Basin	3.5	Lea, Eddy, Reeves, Culberson, Loving, Ward
Eagle Ford	2.6	Webb, La Salle, McMullen, Live Oak, Karnes, DeWitt, Gonzales
Bakken	1.3	McKenzie, Williams, Mountrail, Dunn, Richland, Billings
Midland Basin	0.8	Midland, Glasscock, Reagan, Upton
Three Forks	0.6	McKenzie, Williams, Mountrail, Dunn

Exhibit 15: Comparison of core areas in tight oil plays (IHS, DrillingInfo and Kimmeridge estimates)

Comparison of All Significant US Tight Oil Plays

Extending our analysis to all of the significant tight oil plays in the US, which incorporates over 25,000 horizontal wells, it is clear that most counties within the Delaware Basin rank in the top-right quadrant with best well performance and most repeatable completions *(Exhibit 16)*. Within the Delaware Basin, Culberson County wells rank highest for average well performance, and third highest for repeatability.

In contrast, all of the Midland Basin counties rank in the bottom two quadrants. In the Eagle Ford, around half the counties rank in the top-right quadrant, and the other half in the bottom-right quadrant. Notably, none of the Bakken/Three Forks counties rank in the top-right quadrant – the Parshall oil field does rank in this quadrant, but is arguably a conventional oil field. Of the other plays, only a single county in the Niobrara, one county in the Utica and one in the Woodford rank in the top-right quadrant.

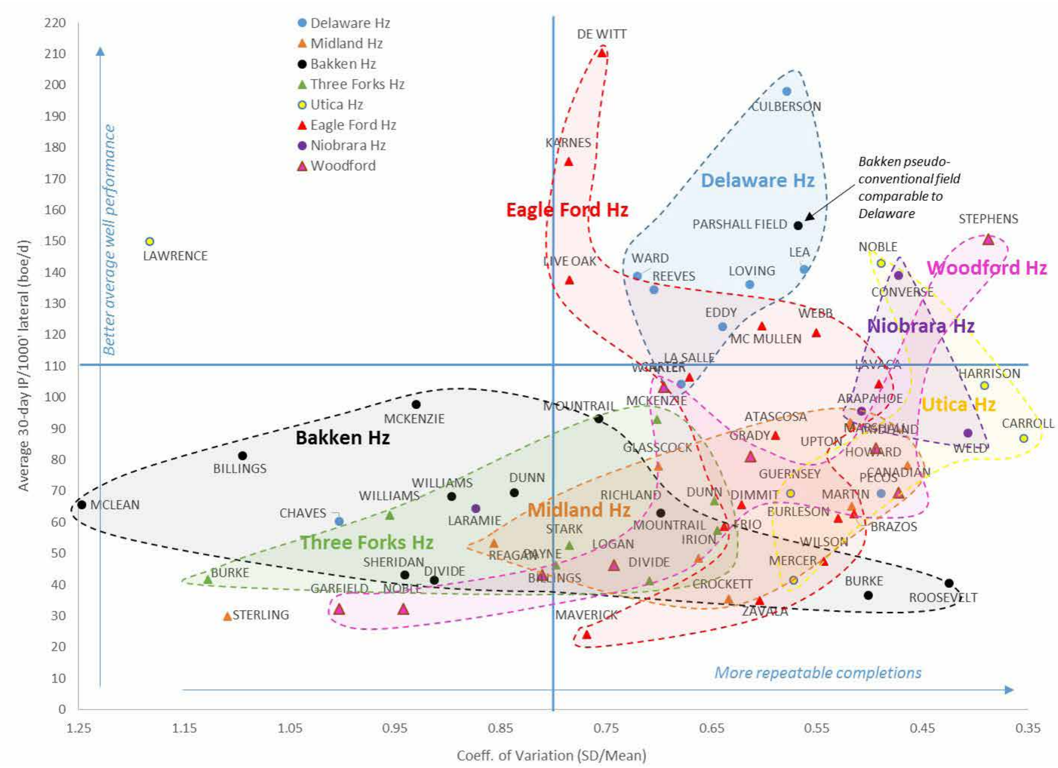


Exhibit 16: 30-day IP/1,000' of lateral versus coefficient of variation for significant US tight oil plays (IHS, DrillingInfo and Kimmeridge estimates)

One of the issues with our analysis is the definition of a liquids play, since some of these have much higher gas content, and are therefore less valuable per barrel produced. Since gas is a much smaller molecule than oil, it is considerably easier to produce from tight reservoirs, so well performance can be as much a function of gas content as other geological factors. Additionally, since gas prices have been so low in the US and well below the BTU-equivalent to oil of 1:6, it is worth normalizing our well performance data for oil content and using an oil-to-gas ratio of 1:16 based on current commodity prices *(Exhibit 17)*.

Interestingly, although there is a considerable shift for some counties that are heavily skewed to one commodity, most of the Delaware Basin counties continue to rank in the top-right quadrant, and Culberson (where wells have higher gas content) ranks as the second best county after Lea, which has seen more drilling activity.

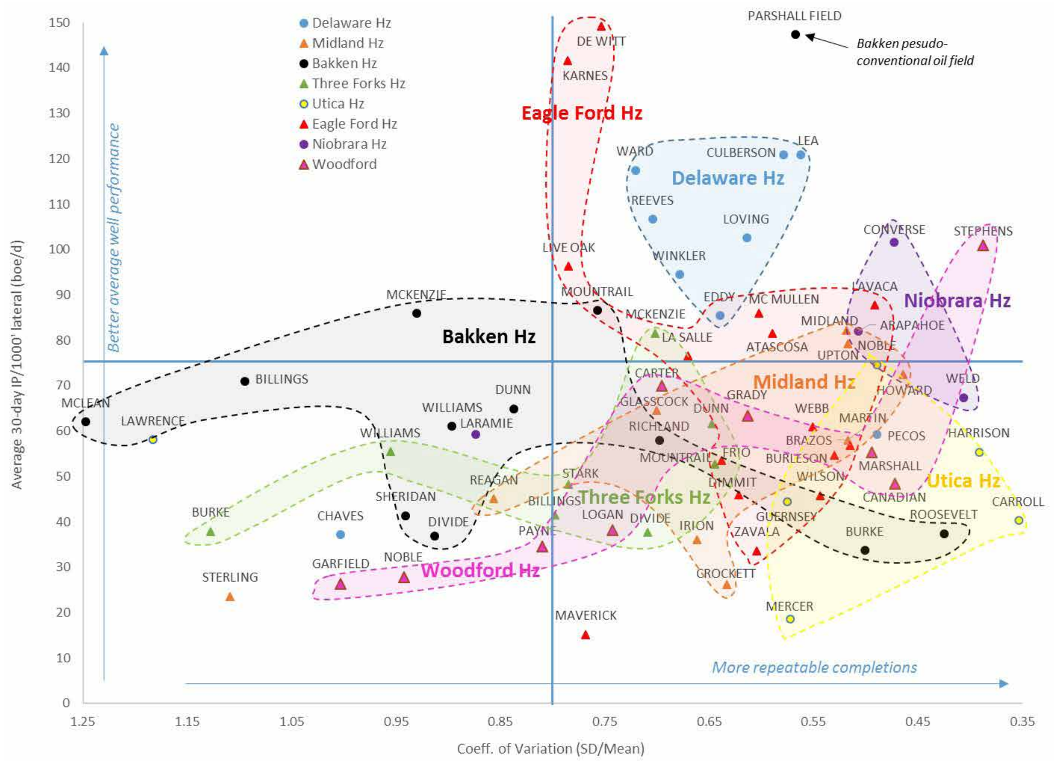


Exhibit 17: 30-day IP/1,000' of lateral versus coefficient of variation for significant US tight oil plays, adjusted for current oil and gas prices and liquids content (IHS, DrillingInfo and Kimmeridge estimates)

Two counties in the Midland Basin now rank in this top-right quadrant, while the Eagle Ford is largely unchanged. Only one Bakken county (Mountrail) and one Three Forks county (McKenzie) push into this quadrant. Notably, none of the Utica counties now rank in the top-right quadrant, while two out of three Niobrara counties rank in the top-right quadrant.

One final issue to consider is the evolution of plays, since the Bakken came much earlier than the others and operators in that play had the opportunity to apply their experience to newer plays such as the Delaware Basin to shorten the learning curve and improve well performance faster through more intense completions.

In order to understand if there is a significant bias against the Bakken as the oldest play, we should look at wells drilled from 2010 onwards, when operators started to use >500 lbs/ft of proppant *(Exhibit 18)*. Using only wells drilled in the four core counties (McKenzie, Mountrail, Dunn and Williams), we can observe that the intensity of completions does increase from 2010 onwards (averaging around 390 lbs/ft vs. 195 lbs/ft in prior years), but the average well performance stays almost exactly the same at around 85 boepd/1,000' of lateral *(Exhibit 19)*.

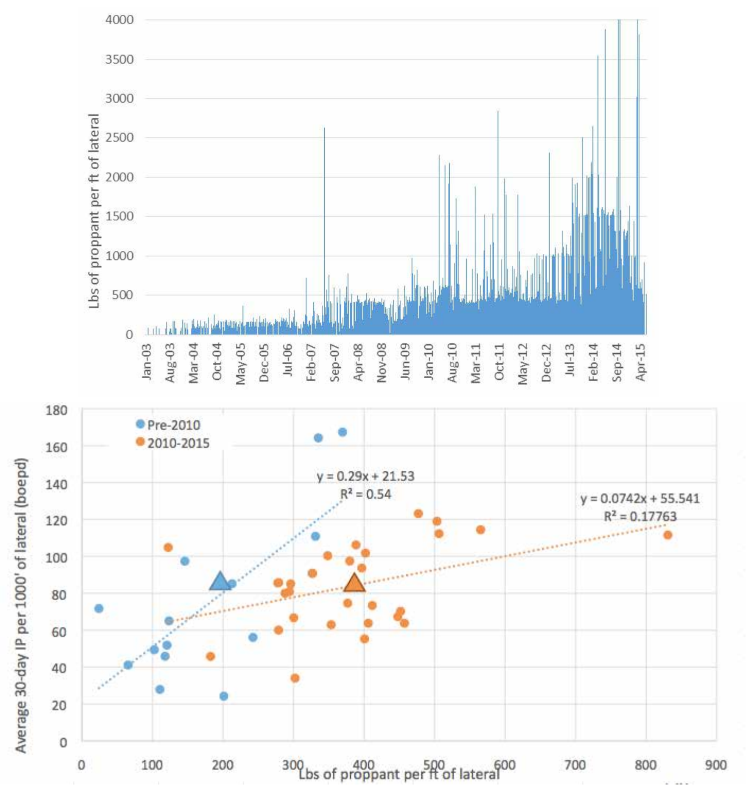
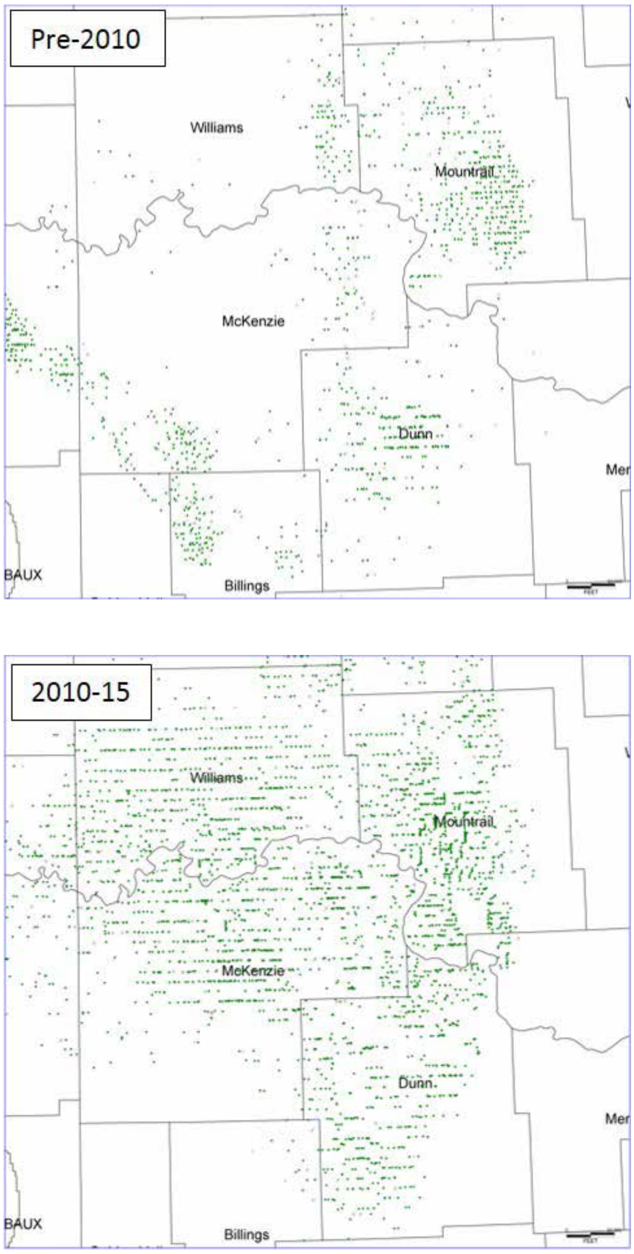


Exhibit 18 & 19: Pounds of proppant per ft of lateral over time in the Bakken; 30-day IP/1,000' of lateral vs. Lbs of proppant for operators in core Bakken counties (IHS and Kimmeridge estimates)

One explanation for this is deterioration in the geology, which offsets the increase in completion intensity. Looking at the geographic spread of wells within our four core counties, there does appear to be a shift in focus towards McKenzie and Williams post-2010 *(Exhibits 20 & 21),* as the geology of the play was better understood and the play fairway extended. Based on these maps, it appears that companies shifted their focus away from "conventional" oil fields such as Parshall in Mountrail County, to the true unconventional play further west in McKenzie and Williams.



Exhibits 20 & 21: Bakken completions pre-2010; Bakken completions from 2010-2015 (IHS and Kimmeridge estimates)

Given that the best Bakken wells are those in the Parshall field, and the true unconventional Bakken play was mainly drilled post-2010, we do not believe that the age of the play significantly biases the Bakken well performance downwards versus newer plays. The much lower completion intensity in the Bakken is likely associated not with age, but with the thinness of the target Middle Bakken reservoir, which is typically 20-75' thick and sandwiched between two ductile shales; this may limit the marginal returns of increasing completion intensity, since vertical fracture propagation is limited. Therefore, although Bakken completions have increased in intensity over time, they have not increased to the same extent as the Permian Basin, where fracture intensity has moved from an average of around 500 lbs/ft in 2010 to almost 1,500 lbs/ft in 2015 *(Exhibit 22).*

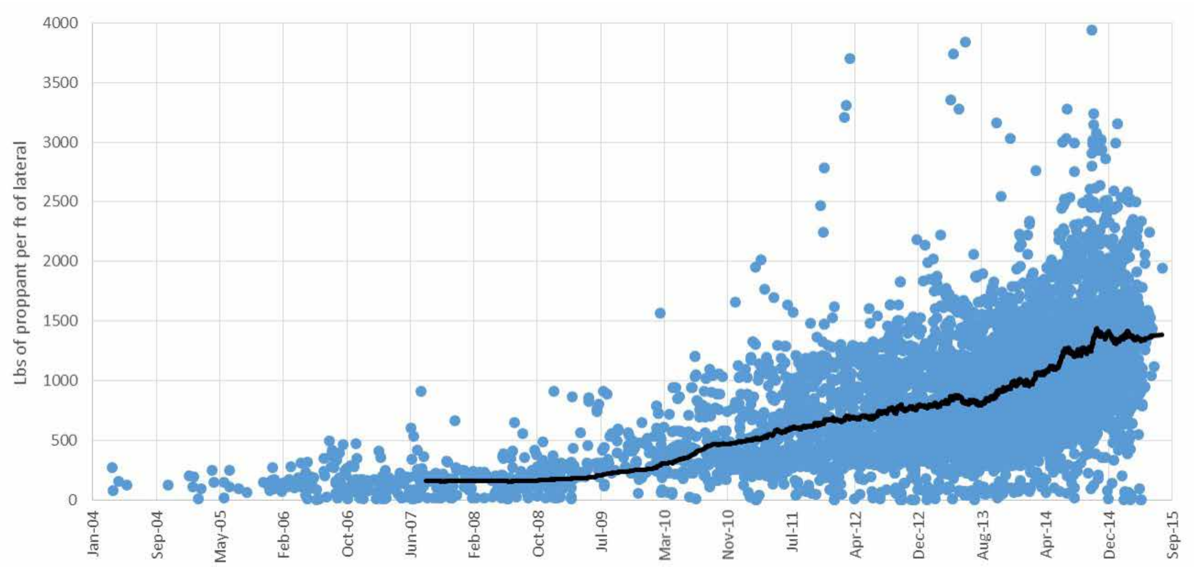


Exhibit 22: Lbs of proppant/ft of lateral over time in the Permian Basin (IHS and Kimmeridge estimates)

Conclusion

Kimmeridge has amassed a database of over 25,000 horizontal wells with well performance and completion data covering all of the significant tight oil plays in the US. Well performance and repeatability are fundamental to understanding the value of an asset, since the other key variable for E&P companies is the amount of acreage under lease. The valuation of any company's E&P asset is essentially a function of these three variables, with asset quality stemming from well performance and repeatability, and asset scale stemming from the size of the acreage position. The best operators in any unconventional resource play will have a position of significant scale in the geologic core and have drilled enough wells to optimize completions, prove up reserves and HBP acreage. The process of completion optimization is iterative, with continuous learnings. Therefore, it is crucial to amass and analyze as much completion data as possible from other operators in the same play and wells in potentially analogous plays.

Our analysis of this large dataset of horizontal wells indicates that the grandfather of US tight oil plays, the Bakken shale, ranks behind newer plays like the Eagle Ford and Delaware Basin on both well performance and repeatability of completions. Meanwhile, the Woodford and Utica appear to have inferior well performance and repeatability.

Drilling down further into the data, we can see that for a given formation in one county (reducing variability from geology), we can isolate the effect of completion intensity on well performance. Specifically, for Wolfcamp wells in Reeves County there is a >80% correlation between IP/1,000' of lateral and lbs of proppant/ft of lateral.

Within the Delaware Basin, Culberson County is emerging as a core area of the play, along with more established counties such as Eddy, Lea, Loving, Reeves and Ward. And although Culberson wells tend to have higher gas content than other counties, well performance adjusted (down) for the current ratio of commodity prices (1:16), still results in Culberson ranking as one of the best counties in what we believe is the best tight oil play in the US. Indeed, our estimate of the areal extent of core acreage in the Delaware Basin is around 35% larger than the Eagle Ford. Additionally, while the Eagle Ford has two productive intervals, the Delaware Basin in places could have up to five stacked productive intervals, meaning a much larger drilling inventory.

Overall, we believe that the Delaware Basin is the premier tight oil play in the country, with the best well performance, most repeatable completions and largest drilling inventory based on both areal extent of the core and stacked productive intervals. Based on company presentations and drilling activity across the US, it is clear that companies are reallocating capital to drilling in the Delaware Basin, or acquiring acreage to enter this prolific play.

Appendix – Geologic Summaries of Tight Oil Plays (in chronological order)

Bakken (2005 onwards)

The Bakken is the first tight oil play to be developed in the US, having been initially tested with horizontal wells as far back as the mid-90's, although the major breakthrough came in the early- to mid-2000's with the application of hydraulic fracturing in horizontal wells.

Although the Williston Basin was not a massive hydrocarbon province prior to the modern era of the Bakken and Three Forks plays, it did have a wealth of geological and geochemical data, which helped in the initial definition of the core of the unconventional plays. In fact, modern geochemical techniques such as rock eval pyrolysis were pioneered in the analogous Paris Basin in France and the Williston Basin in the 1970's and 80's. Perversely, the modern theory of petroleum systems with migration of hydrocarbons from source to trap was developed in the Williston Basin, and the Bakken was proposed as the source from which oil had migrated up faults into shallower Madison reservoirs.

Since then, more detailed geochemical typing has shown the Madison formation to be self-sourced, and the Bakken to be an unconventional system with very little expulsion and migration of oil into shallower reservoirs. The bulk of the oil generated and expelled from the Bakken shales has remained within the Lower Lodgepole, Upper Bakken shale, Middle Bakken siltstone, Lower Bakken shale and Three Forks formation *(Exhibit 23)*. A quiet tectonic setting in the Williston Basin has resulted in limited faulting and therefore minimized migration pathways away from the Bakken.

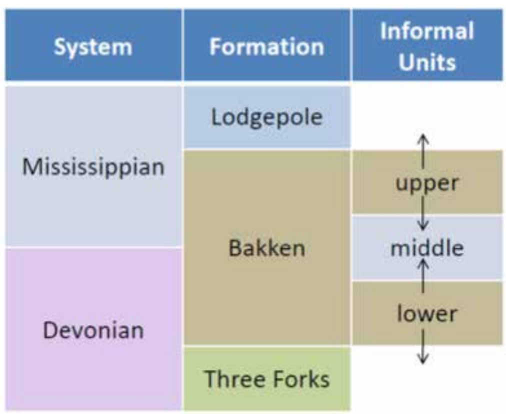


Exhibit 23: Williston Basin stratigraphy in the Mississippian and Devonian (Nordeng - NDGS)

A cross-section with type logs from the center of the basin in northeast McKenzie and southwest Williams Counties *(Exhibit 24)* shows the various units in the Bakken and Three Forks plays. Within the Bakken formation, the primary target interval is the Middle Bakken dolomitic sand or siltstone, which has been charged with oil from the very high TOC-bearing (up to 25% original TOC) Upper and Lower Bakken shales.

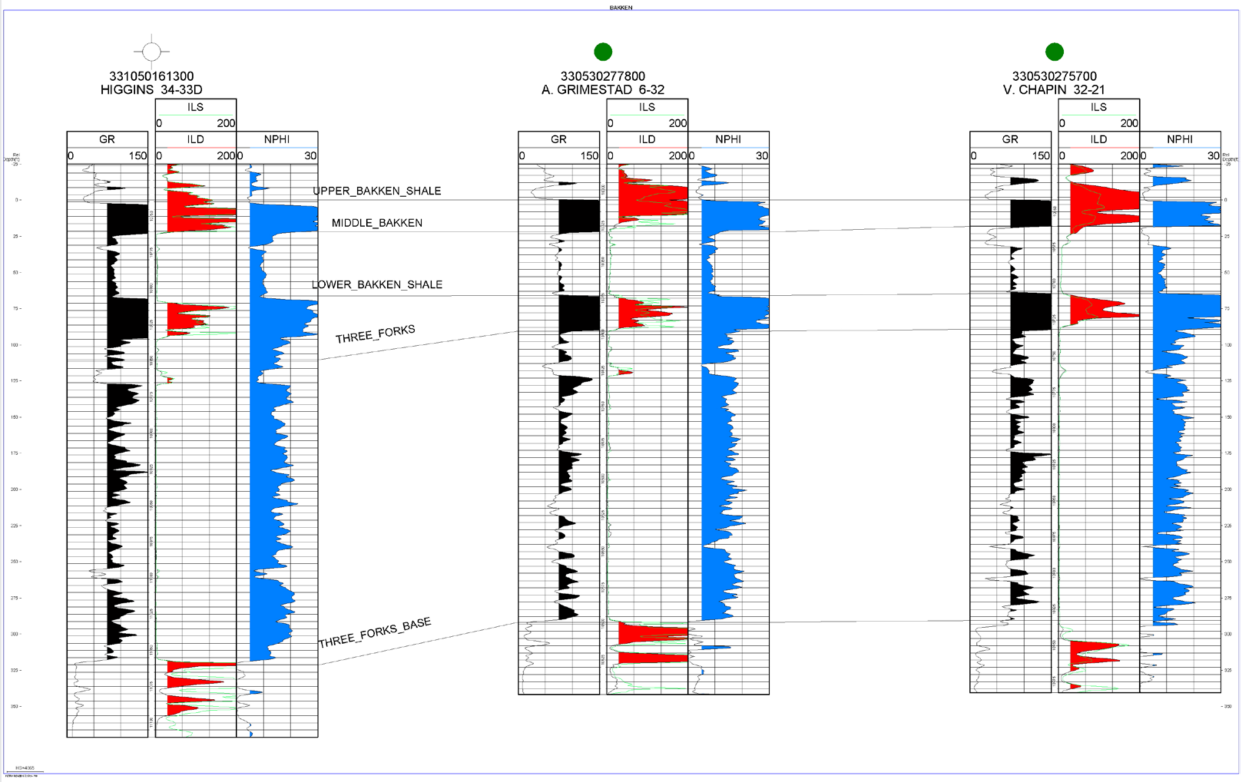


Exhibit 24: Cross-section from basin center showing type logs with gamma ray, deep resistivity and neutron porosity (IHS and Drilling Info)

The Three Forks formation sits below the Bakken formation and has been charged by the Lower Bakken shale, and the target interval is the top 50', as this has the best hydrocarbon charge. Interestingly, while log data is widely available across the Williston Basin, it can be misleading through the Bakken interval due to wide variations in formation water salinity. Crain's Petrophysical Handbook notes:

"Even more confusing is the water resistivity variation on the northwest and northeast edges of the Basin. Here, wet wells have higher resistivity than oil wells further south because the water resistivity is 5 to 20 times higher than deeper in the Basin. This results from fresher water recharge from the Black Hills of North Dakota....Water salinity in the deeper North Dakota wells reaches 325,000 ppm, making for exceedingly low water resistivity."

Consequently, deep resistivity from wireline logs is not a useful indicator of oil saturation, unless it is corrected for water salinity and formation temperature. It is clear from the type logs above in the core of the play (basin center) that deep resistivity is very low in the Middle Bakken and Upper Three Forks, yet these are the target intervals that we know to be oil-saturated due to the thousands of producing wells.

However, geochemical data from cores through the Bakken and Three Forks do allow us to determine oil saturation *(Exhibit 25)*. A geochemical type log, shows the high TOC's in the Bakken shales up to 15%, S1 up to 10 mg HC/g TOC, Tmax >435, and S1/TOC >100 throughout the Middle Bakken and Upper Three Forks. The latter measure indicates oil saturation, since lab tests have shown that organic material can absorb around 100 mg HC/g, so anything above 100 is assumed to be free, producible oil. As can be clearly seen, this suggests producible oil throughout the Middle Bakken and in the top 50' of the Three Forks.

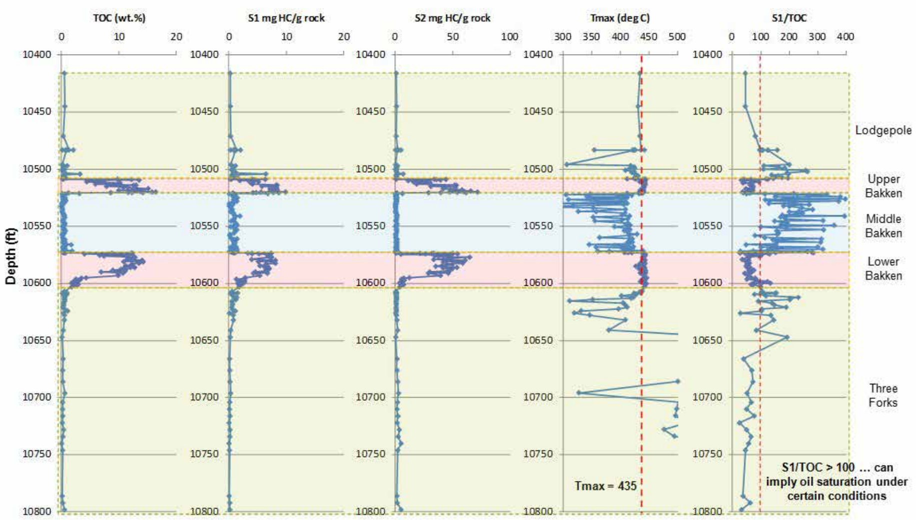
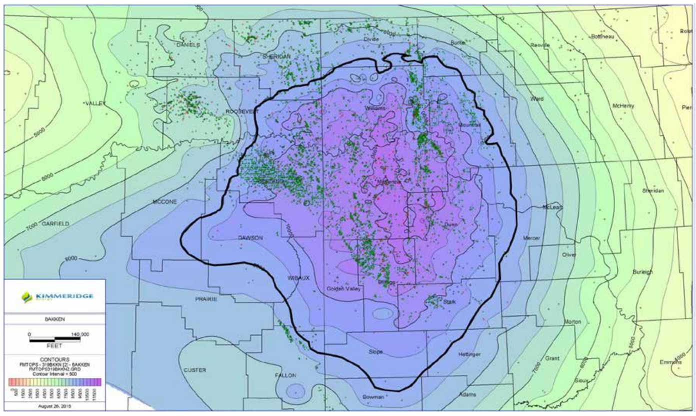


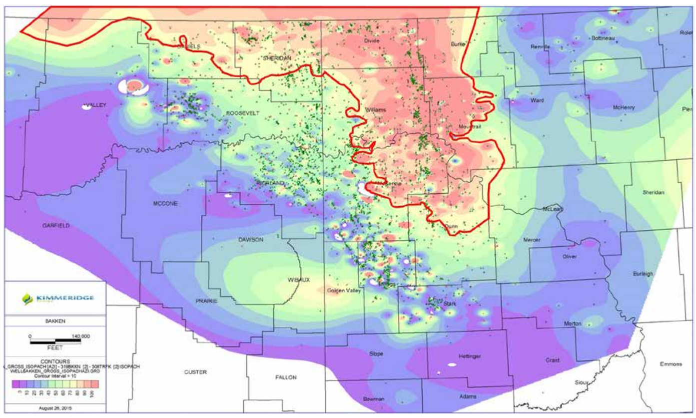
Exhibit 25: Geochemical type log (NDGS)

The wealth of geochemical and geological data for the Bakken allows us to define the core area for the unconventional plays. Specifically, for the Bakken, we can use the following basic criteria to define the geologic core:

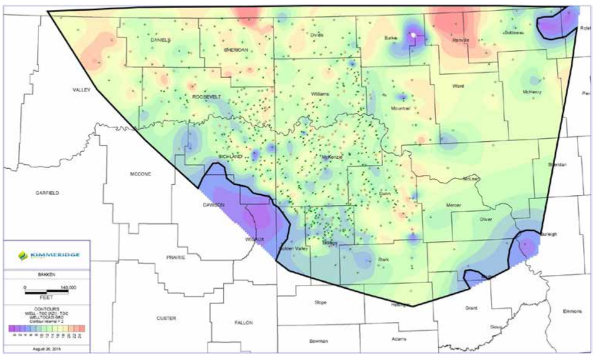
- Depth >9,000' *(Exhibit 26)*
- Gross Thickness >70' *(Exhibit 27)*
- TOC >4% *(Exhibit 28)*
- Maturity Tmax >440 *(Exhibit 29)*
- S1 >6mg/g (*Exhibit 30)*

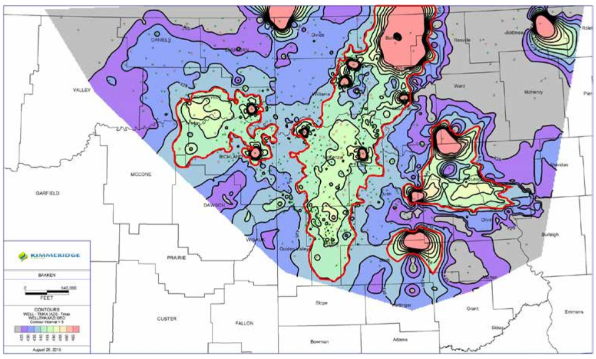
These parameters define a core area for the Bakken tight oil play focused in McKenzie, Mountrail, Dunn and Williams Counties in North Dakota *(Exhibit 31)*. Furthermore, since the Three Forks formation is typically >100' across most of the basin *(Exhibit 32)*, the major constraining factor is oil charge from the overlying Lower Bakken shale. And since the major constraining factor for the Bakken is also oil charge, driven by TOC and thermal maturity, we believe the geologic core of the Three Forks play overlaps closely with the Bakken play *(Exhibit 33)*.



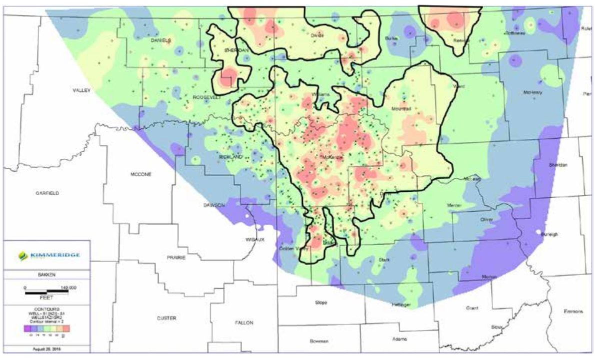


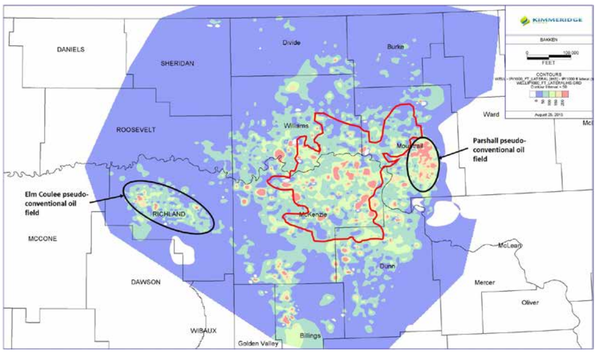
Exhibits 26 & 27: Bakken drill depth with 9,000' contour; Bakken gross isopach with 70' contour (IHS and Kimmeridge estimates)



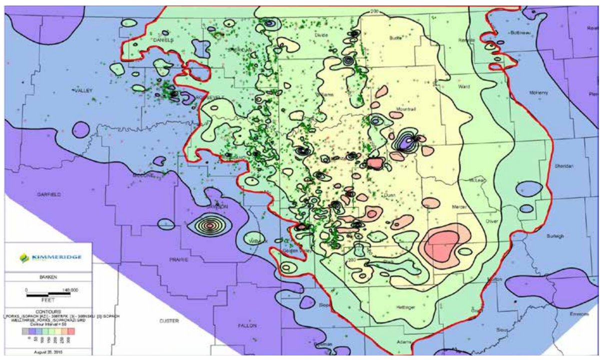


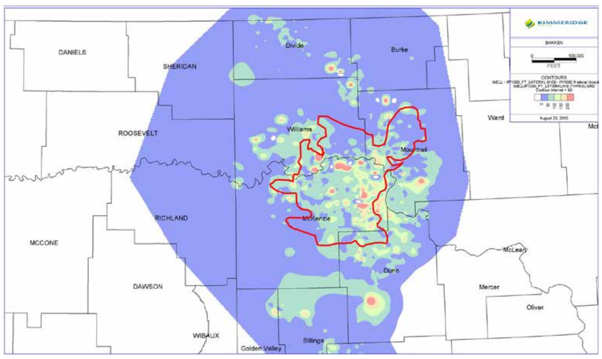
Exhibits 28 & 29: Bakken TOC map with >4% contour; Bakken maturity map with Tmax >440 contour (IHS, NDGS and Kimmeridge estimates)





Exhibits 30 & 31: Bakken S1>6mg/g contour; Bakken 30-day IP/1,000' of lateral, with geologic core overlaid (IHS, NDGS and Kimmeridge estimates)





Exhibits 32 & 33: Three Forks gross isopach with 100' contour; Three Forks 30-day IP/1,000' of lateral, with geologic core overlaid (IHS, NDGS and Kimmeridge estimates)

Eagle Ford (2009 onwards)

The Eagle Ford shale play should really be called the Eagle Ford carbonate source rock play, since it is composed of up to 90% calcite (typically 40-80%), with subordinate amounts of clay (illite, mica, kaolinite) and quartz *(Exhibit 34)*.

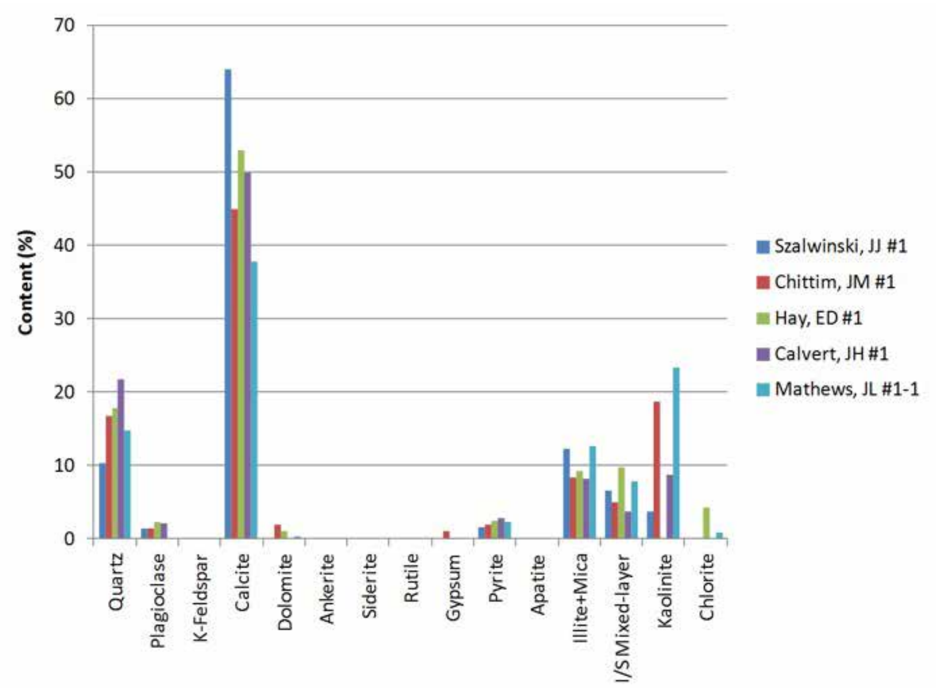


Exhibit 34: Eagle Ford mineralogy (Harbor, 2011)

The Eagle Ford is a gradational sequence that gets more "shaley" and organic-rich towards the base, and the base of the formation is the primary productive interval, since it has the best hydrocarbon saturation *(Exhibit 35).*

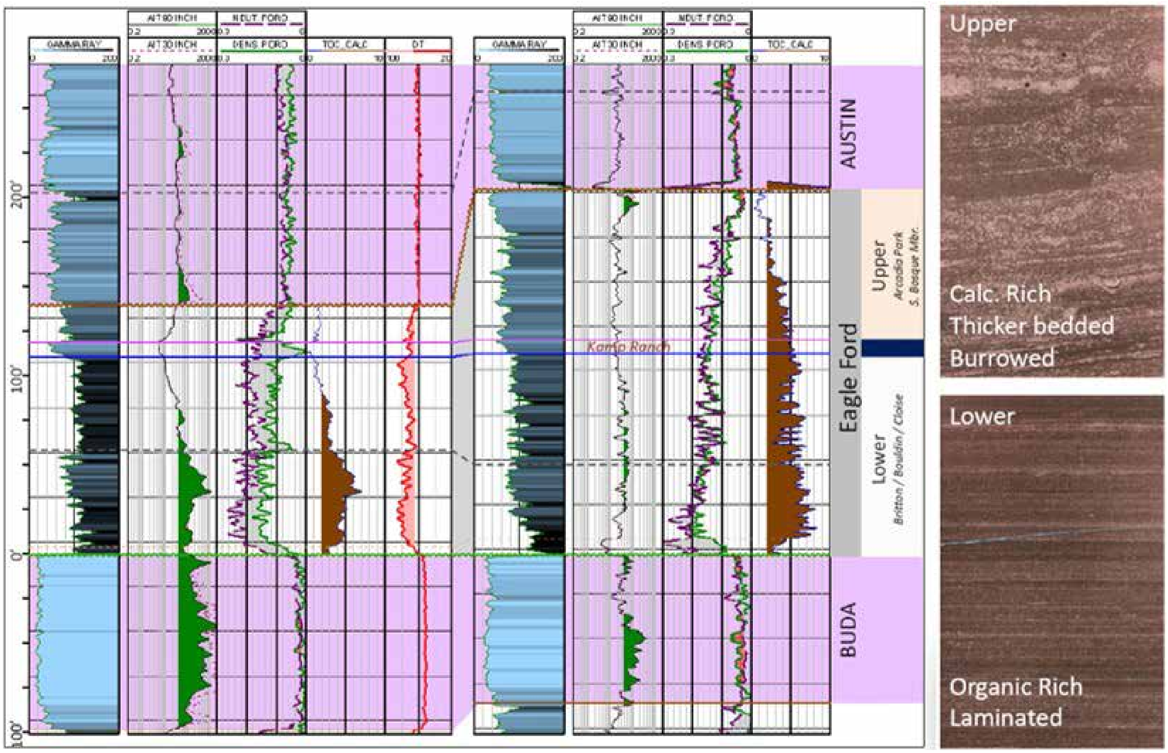
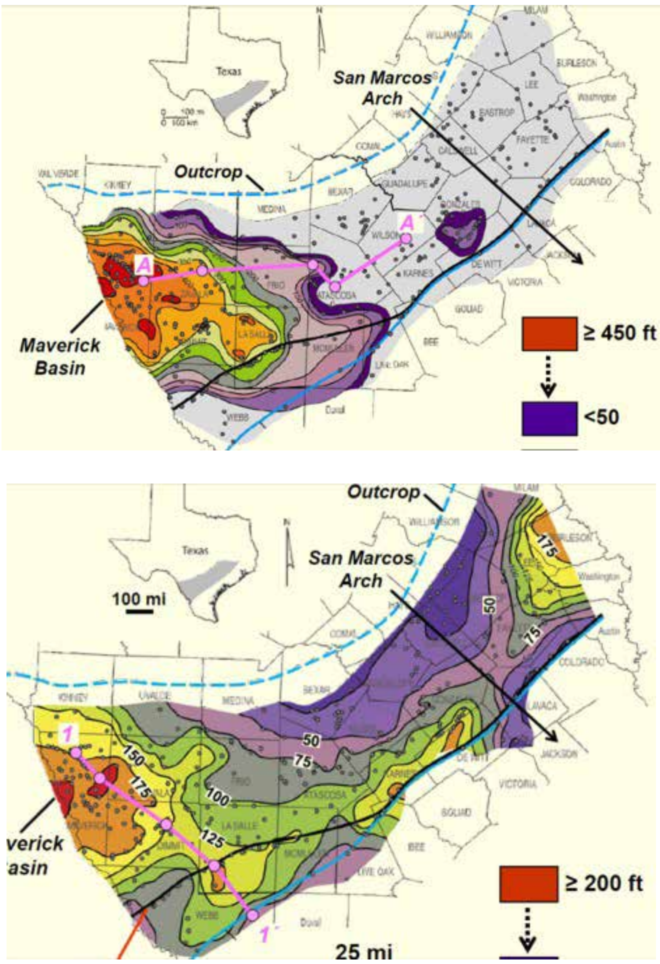


Exhibit 35: Eagle Ford type section (Treadgold et al., 2011)

The Upper Eagle Ford is thin or non-existent on the eastern side of the play, but ranges from 50-450' on the western side of the play, reaching maximum thickness in the Maverick Basin *(Exhibit 36)*. The Lower Eagle Ford is more consistently deposited across the play ranging in thickness from 50-200', again with maximum thickness in the Maverick Basin *(Exhibit 37)*.



Exhibits 36 & 37: Upper and Lower Eagle Ford isopach maps (Hentz & Ruppel, 2011)

The Eagle Ford in the oil window (Tmax 438-444) displays the characteristic crossover effect with S1/TOC over 100 mg HC/g TOC, which indicates producible oil *(Exhibit 38)*. Laboratory studies indicate that organic-rich shales can absorb around 100 mg of oil per gram of TOC, so anything in excess of this is free/producible oil. In the charts below, this is indicated by the green-shaded area where S1 (mg/g) exceeds TOC (wt. %).

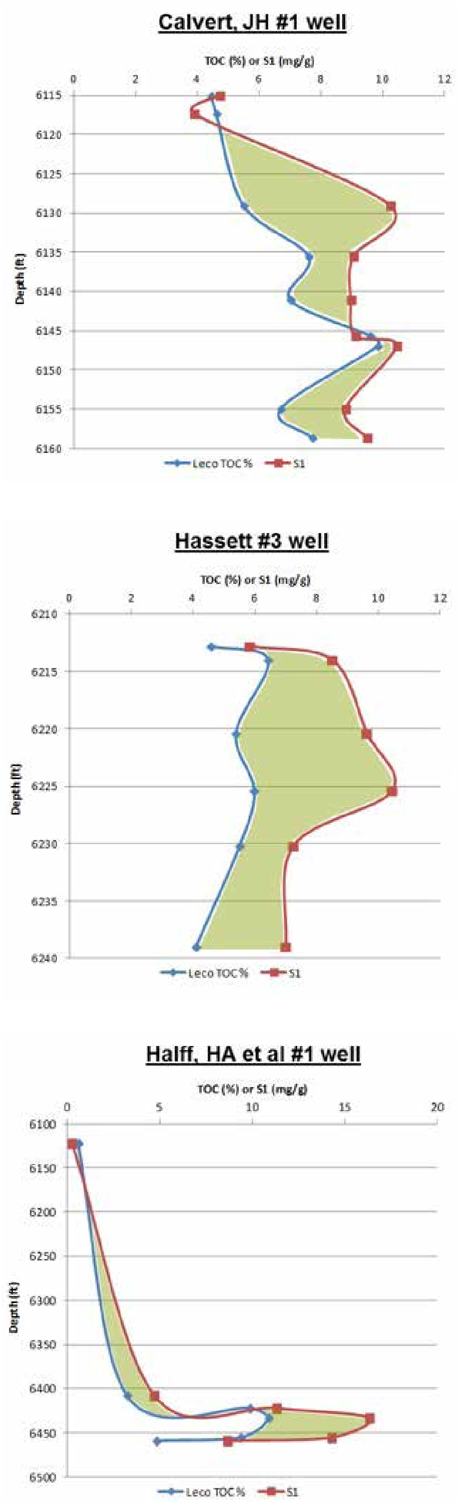
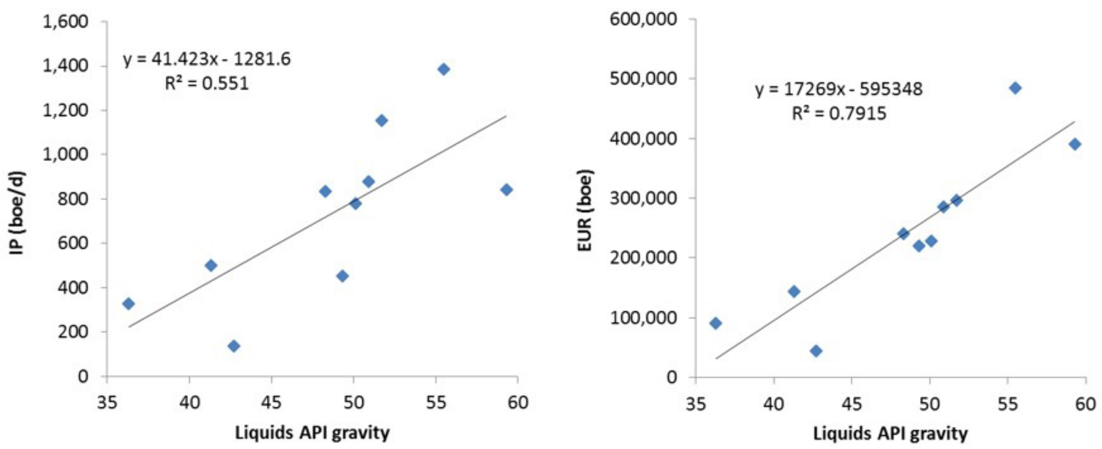


Exhibit 38: Eagle Ford TOC and S1 for select wells with crossover effect (Harbor 2011 and Kimmeridge estimates)

In fact, well performance in the Eagle Ford is largely a function of hydrocarbon phase and reservoir pressure. The higher the API gravity of the oil, the higher the IP and EUR *(Exhibits 39 & 40)*. This makes sense intuitively, since lighter hydrocarbons are composed of smaller molecules, and thus flow more easily through tight rocks.



Exhibits 39 & 40: Eagle Ford IP and EUR vs. API gravity (Swindell 2012 and Kimmeridge estimates)

Thermal maturity is governed by depth, with the oil window ranging from around 4,000-12,000', the condensate window ranging from 7,000-15,000' and the dry gas window ranging from 10,000-16,000'.

Hydrocarbon phase is governed by thermal maturity – so the deeper and more mature, the lighter the hydrocarbons and the more gas in the system.

Reservoir pressure also increases with depth, both in absolute terms and pressure gradient, since more conversion of kerogen results in more geopressuring of the formation as volumetric expansion of liquids and gases occurs as kerogen is transformed into hydrocarbons.

Consequently, the focus of drilling in the Eagle Ford has been within the late oil and condensate windows, due to a combination of the best productive characteristics and the presence of liquids (oil and condensate), which are more economic than dry gas, especially since the dry gas window is very deep and therefore expensive to drill *(Exhibit 41)*.

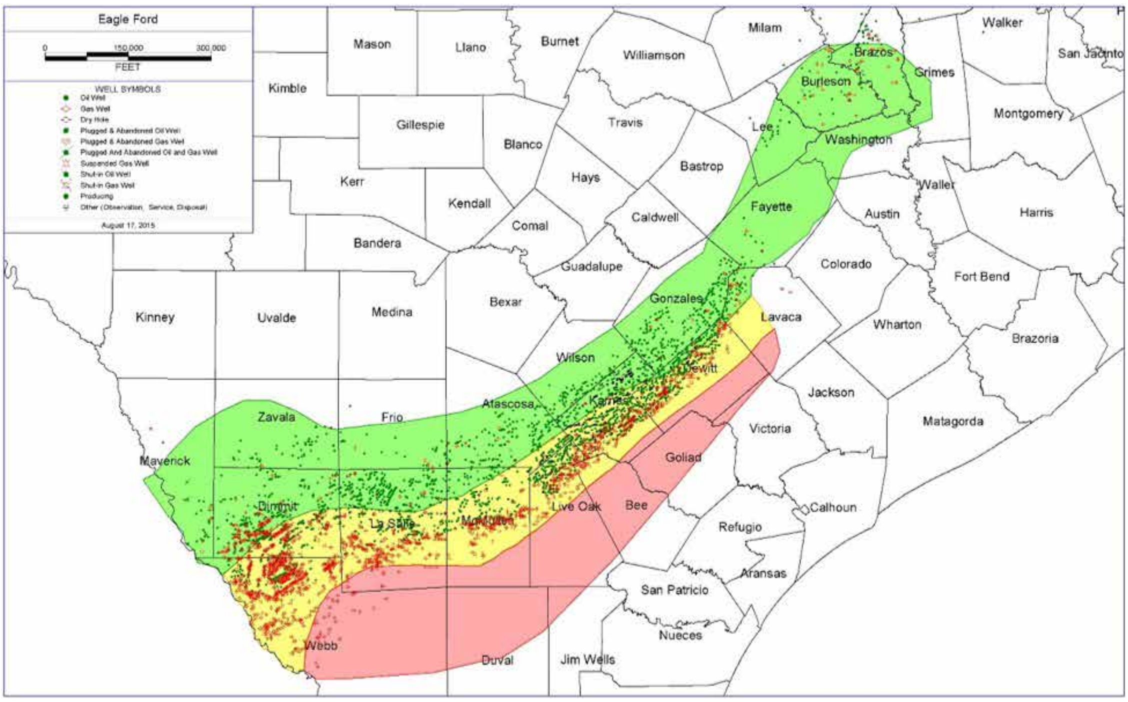


Exhibit 41: Eagle Ford oil, condensate and gas windows (EIA, DrillingInfo and Kimmeridge estimates)

Indeed, if we look at IP/1,000' of lateral, it is clear that the best wells lie within the late oil-to-condensate zone, with very few wells drilled in the dry gas window *(Exhibit 42)*.

Interestingly, because the main target of the Lower Eagle Ford is relatively thin (50-200'), thickness is not a primary driver of the core of the play. Sufficient thickness (>75') is required to complete a fracture-stimulated well, but the thickness is not a big driver of well performance, since some of the best wells are in the eastern and central parts of the play, whereas the thickest Eagle Ford is on the far western side.

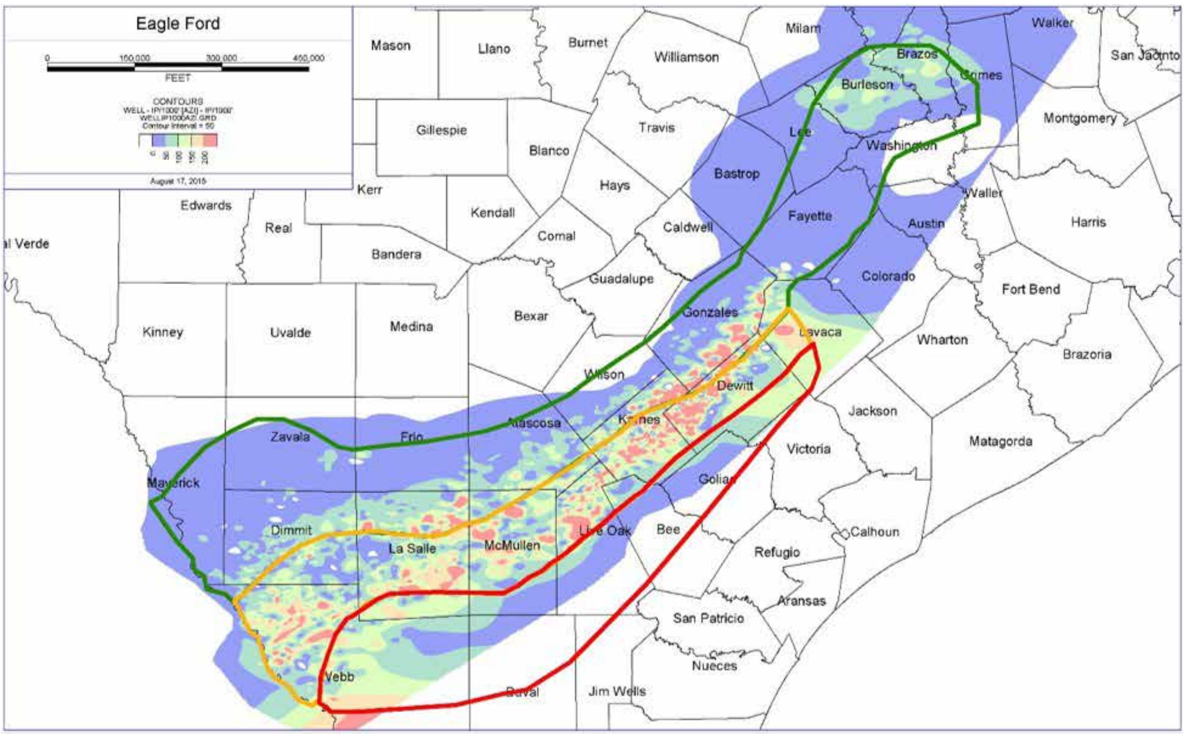


Exhibit 42: Eagle Ford oil, condensate and gas windows, versus 30-day IP/1,000' of lateral (EIA, DrillingInfo and Kimmeridge estimates)

Permian Basin (2010 onwards)

Because Kimmeridge has its largest investment in the Permian Basin and a differentiated view of the geology, we have not included detailed geologic analysis of the basin.

Utica Shale (2011 onwards)

The Utica shale is a type II, oil-prone source rock, with moderate TOC of around 2-4%. The Utica play is composed of two units: the Utica shale and the Point Pleasant formation; the latter is a calcareous shale with lower clay content and higher carbonate content *(Exhibit 43)*. This means the Point Pleasant is more brittle and susceptible to fracturing, both naturally and as a result of hydraulic fracturing, so completions have been focused on this formation.

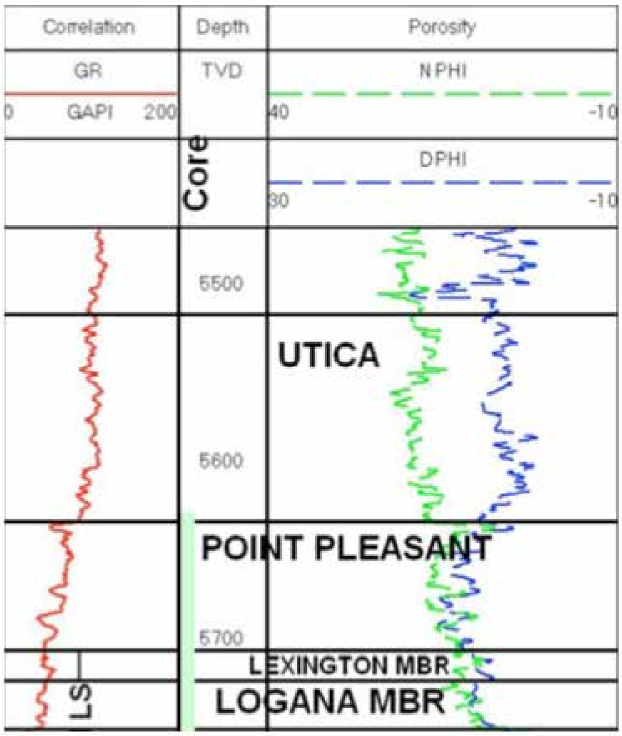
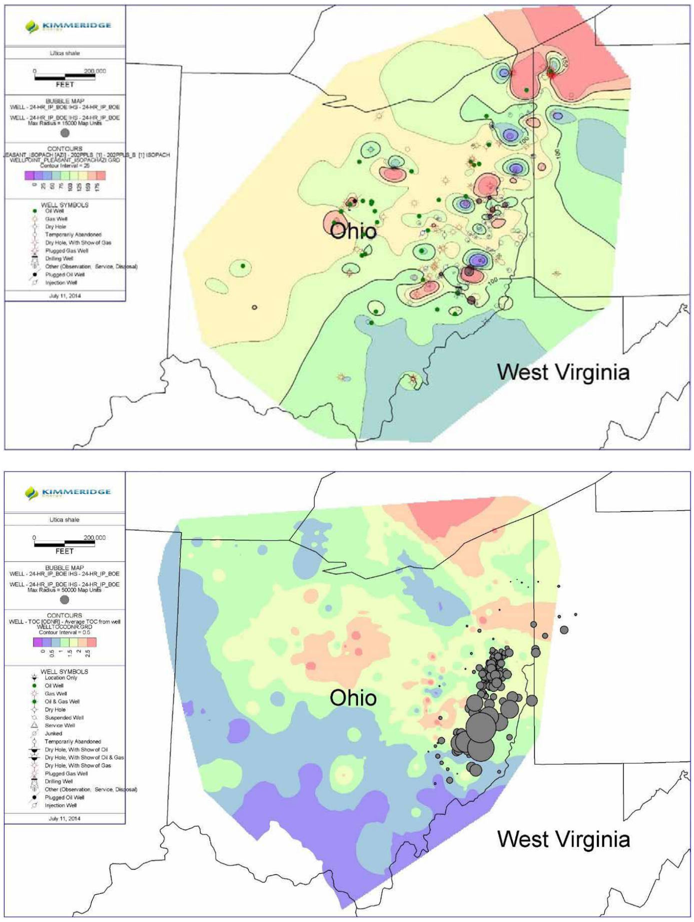


Exhibit 43: Utica shale plays type log (Wickstrom, ODNR)

Although the number of wells drilled is relatively low, the play has garnered a lot of attention due to some huge IP rates on early Chesapeake wells. However, the play has disappointed in terms of its areal extent, produce-ability in the oil window, liquids content and consistency of well results.

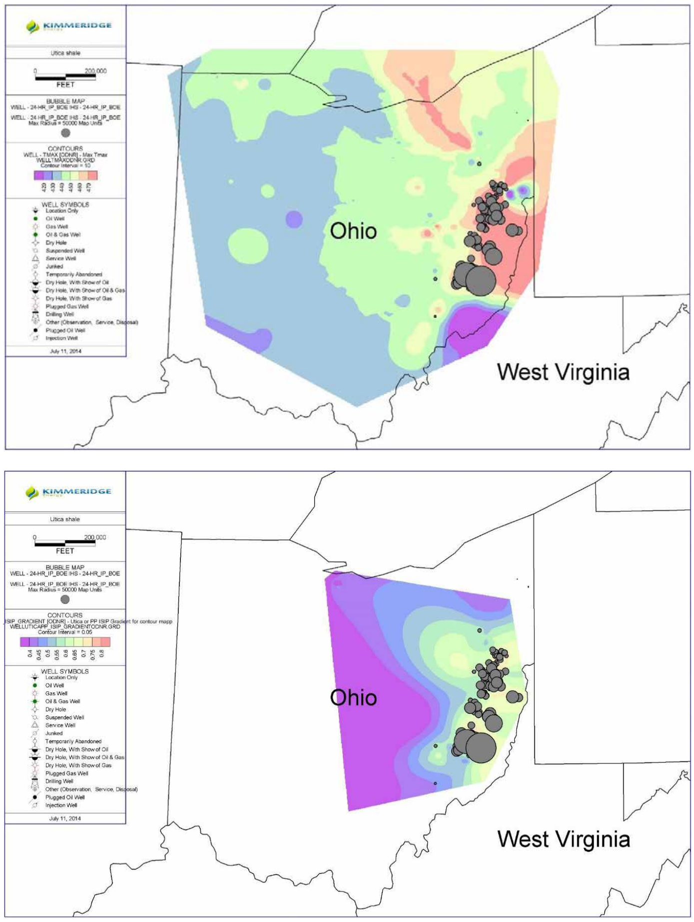
The primary play area is in eastern Ohio, where the Utica shale is in the late oil-to-early gas window. We can overlay attributes such as thickness and TOC *(Exhibits 44 & 45)* to derive a core area; however, given what we know about the play based on well results, the key constraining factor is thermal maturity, which governs hydrocarbon phase and reservoir pressure.

Indeed, across most of Ohio the Point Pleasant has thickness of >100', and in northern Ohio, TOC >1%. The bubbles indicate the wells that have been drilled and their relative IP's.



Exhibits 44 & 45: Utica shale isopach map; Utica shale TOC distribution map (IHS, ODNR and Kimmeridge estimates)

The most telling maps are those of thermal maturity and reservoir pressure *(Exhibits 46 & 47)*, with almost all of the wells drilled in the play within the area with Tmax >460 (late oil-to-condensate window) and reservoir pressure >0.6 psi/ft. Wells drilled further west in the early/black oil window have been largely uneconomic with much lower IP rates.



Exhibits 46 & 47: Utica shale maturity Tmax map; Utica shale reservoir pressure map (IHS, ODNR and Kimmeridge estimates)

Additionally, while some initial production rates have been excellent, some wells have seen precipitous drops in liquids production, as reservoir pressure drops below bubble/dew point pressure, resulting in phase separation in reservoir. This leaves behind much of the liquids production and results in a spike in GOR, a decline in flow rate and ultimately less economic wells.

If reservoir pressure is not much higher than the saturation pressure (bubble/dew point) of the hydrocarbons in reservoir, then the time to saturation and phase separation can be short. In the Utica wet-gas window, the pressure gradient is typically 0.6-0.7 psi/ft at depths of 7,000-8,000', resulting in typical reservoir pressures of 4,000-5,500 psi.

High saturation pressure results from mixed fluids, biodegradation or biogenic methane. For the Utica, saturation pressure is likely high, due to mixed fluids in reservoir (oil, condensate and NGL). Saturation pressures close to or >5,500 psi would result in rapid phase separation. Choking back wells to control this issue has become a major focus for operators such as Gulfport.

Indeed, despite the massive areal extent of the Utica shale and consistent quality and thickness over large areas, the steep gradient in thermal maturity, with a resulting steep gradient in hydrocarbon phase and reservoir pressure, has rendered the core of the Utica liquids play relatively small *(Exhibit 48).*

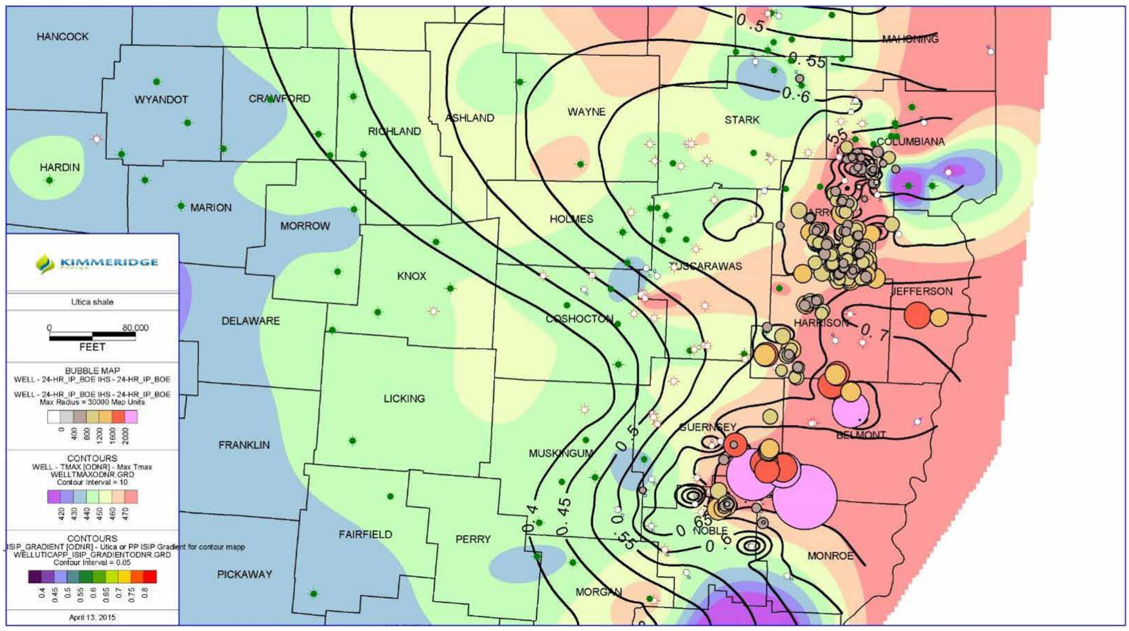


Exhibit 48: Utica shale core area (IHS, ODNR and Kimmeridge estimates)

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