The Paradox of Increasing Initial Oil Production but Faster Decline Rates in Fracking the Bakken Shale: Implications for Long Term Productivity of Tight Oil Plays

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Highlights:

- Tight oil plays will dominate U.S. hydrocarbon production for next few decades
- Well production shows increased IP associated with sharper decline as play matures
- Increased initial production of Bakken well does not reflect higher lifetime recovery
- Intense fracking results in higher initial production and more rapid terminal decline

Abstract:

In the US, tight oil is the largest source of liquid hydrocarbons and has driven the country to become the world's largest oil producer. Eventually many countries will likely be producing very large quantiles of tight oil. However, how robust is tight oil production? The answer to this question will have an impact on the future geographic spread of oil production and will have geopolitical implications. The estimated ultimate recovery (EUR) and rate of production decline are key metrics in the evaluation of the future productivity of tight oil wells. To understand the nature of production decline of tight oil wells we chose the Bakken Shale because availability of the high quality, publicly available data. Traditionally, well operators have estimated the EUR for each well from the initial production (IP), using empirical type curves to extrapolate to the ultimate production.

From 2015 to 2018 the IP of the average Bakken well increased by approximately 50%. This increase resulted in claims by operators and in the academic literature that more intense hydraulic fracturing was increasing the average EUR of the Bakken play. At the same time, other observers claimed the wells

declined much more rapidly than previous wells. This faster decline provided evidence for lower ultimate production from newer wells. The aim of this study was to understand the origin of these seemingly conflicting observations. A physics-based, scaling model was used to predict production from horizontal multi-stage fractured wells. The scaling model was applied to a very large data set of 13,444 wells. The EUR and terminal decline rate (TDR) were estimated from fitting production to our scaling model.

Our study found that implementation of more, intensive fracturing resulted in higher IP and steeper terminal-production declines. Recently published results estimating the total production from the Bakken that include increased lifetime production commensurate with observed increases in average IP, significantly overestimate the long-term production potential of tight oil, both in the US and globally.

Introduction

Tight oil production has drastically altered the US energy landscape, and this could spread to other countries. In 2018, the US became the largest oil producer in the world. In 2019, US tight oil (that requires hydraulic fracturing to produce) reached a production high of 7.7 million barrels per day 63% of total U.S. production, with the Bakken accounting for nearly one third. Eventually, many countries will likely produce very large quantiles of tight –oil, this is already starting in Argentina. As other countries develop tight oil production, they will reap the rewards of increased economic activity and the balance of production could shift away from OPEC, with geopolitical implications.

For all these reasons, the rate of decline of tight oil wells and their lifetime productivities have very important implications on the future global oil supply. Estimating the long-term decline of individual wells is the key to evaluating the future oil production from tight oil plays. Over the last decade, tight oil operators in the Bakken play have tripled the initial 12-month cumulative production for the average well. This increase in initial production (IP) has been interpreted as reflecting a major increase in the producible reserves of the Bakken tight-oil play (and by analogy the ultimate production of oil from other plays such as the Eagle Ford Shale and the Permian Basin). If correct, this conclusion has fundamental implications for not only US oil reserves but also for global oil reserves.

The estimated ultimate recovery (EUR) and rate of decline during production are key metrics for evaluating the future production of tight oil wells. Under empirical type curve analysis, EUR is proportional to initial rates. If this is true, the tripling in initial rates equates to tripling the ultimate recovery. However, production decline rates for new wells are progressively more rapid. This has created an apparent paradox. Operators claim they are increasing per-well EUR, while some analysts, noting increasing decline rates, have suggested that EURs of wells are decreasing. As similar issues are occurring in other tight-oil fields such as the Eagle Ford and Midland basin, this phenomenon has implications for understanding future US oil production. Future tight oil production will have a significant impact on global oil supply. This paper presents an analysis of the decline of Bakken wells that resolves the paradox and provides a robust basis for forecasting future production from tight oil basins.

To understand the nature of production decline of individual wells we have chosen the Bakken Shale because of the high quality, publicly available data set from the North Dakota regulatory agency (Anon, 2020). Wells drilled in tight oil plays have long laterals and intense hydrofracture treatments, unlike conventional plays, and therefore require different analysis.

Several groups have estimated future production from the Bakken, but these estimates vary. The USGS (Gaswirth et al., 2013) estimated "4.4 to 11.4 billion barrels of undiscovered, technically recoverable oil in the Bakken (with a mean estimate of 7.4 billion bbls)". Scanlon et al. (2016) estimated future recoverable oil in the Bakken is 14.4 billion bbls, from 60,000 wells. Based on production data up to

2017, the EIA (2018) estimated proven-reserves in the Bakken play to be 5.45 billion bbls. Scanlon et al. assume that every future well will have an EUR of 240 thousand bbls (the average reported by Male et al., 2017). Also, in 2017, Ikonnikova and Tinker (2017) estimated (4) that oil recoverable from the Bakken was 10.5 billion bbls, from 74,000 future wells (given an oil price is $100 per bbl). The projected oil recovery of Ikonnikova and Tinker is 74% of that of Scanlon et al. The most recent published estimate for the future production in the Bakken is 17 billion bbls for a future oil brice of $200 a bbl, (Smith, 2018). Smith was the first to increment future EURs (by a factor of 1.15), based on the claims that increased IPs were directly proportional to the EURs. Continental Resources, the largest producer in the Bakken, has recently estimated that the play has reserves of 30 to 40 billion bbls of recoverable oil (Steward, 2018). It is clear that there is a large uncertainty in estimates of the oil resources in the Bakken. We will show how the accuracy of estimating the recovery of future wells is key to making robust prediction of the total recoverable resource.

Tight oil operators have promoted their abilities to increase production asserting that in the Bakken, "Early-time production rates" (that they base on 180-day state-reported cumulative production), "have increased 4-fold over [the last decade]" (Pearson et al., 2018). They ascribe this increase to field operator's "innovation and continuous improvement in completions technology" resulting in higher production per well, for ten out of the last twelve years. Continental Resources recently stated that production from 134 optimized completions resulted in a 12.5% increase over the first 300 days of production.

Based on his analyses of production data from Bakken wells, Smith (2018) presented a model for ultimate recovery from the play that included an increase in "fracking efficiency" of 15% per year, roughly consistent with Covert's (2013) estimate of efficiency gains due to industry's progressively better informed choices of fracking inputs. Smith asserted that Bakken production increased by 11.4% per year from 2008 to 2014, as a result of increased efficiency of hydraulic fracturing, specifically optimizing of proppant weights and injected fluid volumes achieving greater fracking intensities. Attanasi and Freeman (2019) have presented an alternative analysis of the Bakken well production. These authors concluded that that “a significant part of the well productivity increases” from 2010 to 2015 was the consequence of “improved well site selection”. By this they mean that in response to lower oil prices, operator’s located wells in areas that they knew from experiences were like ly to be more productive. In contrast, they concluded that from 2015 to 2017, “part of the improved well productivity” was as the result of “substantial increases in the proppant and injection fluids used per stage and per well.”

A different view was expressed five years ago by consultants interested in the decline rate of tight oil wells. In 2015, Art Berman (2015) asserted that only “4% of horizontal wells drilled [in the Bakken] since 2000 meet the EUR … threshold needed to break even”. Also, in 2015 the consultants at BTU Analytics proposed the question in a web article “are new completion designs altering [increasing] first year Bakken declines?” Another recent article (Olson, 2019) said, “Thousands of shale wells drilled in the last five years are pumping less oil and gas than their [operators] forecast,” and that this raised questions regarding “the strength and profitability of the fracking boom.” A recent study by Rystad Energy (reported by the Wall Street Journal) suggests that operators’ productivity predictions are “routinely incorrect” (Olson, 2019) and that tight oil wells will generally produce 10 to 50% less oil and gas than estimated by operators (Wald, 2019). Unfortunately, the data and analyses supporting this assertion are not public.

All of this presents an apparent paradox: how can the initial production from wells be increasing and yet the subsequent production from these wells be declining at a faster rate than expected? If this drop-off is real, what are the implications for estimating the potential for the long-term production from tight-oil plays? These issues significantly affect energy security in the US and a myriad of potential economic impacts.

In this study, we analyzed a large publicly available data set for the completion and production of 13,444 horizontal, hydraulically-fractured, wells from the Bakken shale play. Completion data included the lateral lengths drilled, frac fluid injected, and frac proppant injected during hydraulic fracturing. Production metrics include 20-year EUR, 12-month initial production, and terminal decline rate (TDR).

The aim of this study was to understand the impact of completion techniques in controlling oil production over time in the Bakken. We used a physics-based, scaling model to predict production from horizontal multi-stage fractured wells, developed by Male (2019) and Male et al. (2017) and applied it to a very large data set of 13,444 wells. The EUR and terminal decline rate (TDR) were estimated from fitting production to our scaling model. This work has implications for both (1) understanding whether optimizing well completion techniques can increase the lifetime production from a well; and (2) estimating the long-term production from the Bakken and other tight oil plays. We present evidence that type curve analysis for estimating the long-term production from tight oil plays overestimate production significantly.

Methods

The Publicly Available Bakken Data-Set

The Bakken has one of the longest histories of oil production from hydraulic fracturing and horizontal laterals, going back to the early 2000s. This long history of production makes it an attractive play for the current analysis. This work utilizes production histories from 13,444 wells from the Bakken and the underlying Three Forks Formations in the Williston Basin in North Dakota. The data set begins with wells drilled in 2000 and including up to the end of 2018. Unfortunately, the publicly available data that can be used to characterize changes in completion technology is highly incomplete for some variables. For instance, nearly one-half of the wells do not have their proppant type (sand vs ceramic) reported. The

Bakken has a large number of wells that are in boundary dominated flow (BDF) and that can be used to estimate terminal decline rates (Male et al, 2017).

Estimating Decline Rates

As defined by Arps (1945) the nominal decline rate of an oil well is computed from the production rate decline each year, divided by the production rate at the beginning of that year. The terminal decline rate (TDR) can be estimated from the production rate of a well after it reaches boundary dominated flow (BDF) and begins constant decline rate (exponential) flow (see explanation of the concepts and the geometry of the model in Male, 2019). This rate can only be estimated after a well has been in the BDF regime for over a year. Before the BDF regime, a fractured well's decline curve can be modelled as a set of parallel fractures each draining an unbounded reservoir volume. In this case their productions decline hyperbolically. When the production from each adjacent fracture interferes and the wells enter the BDF regime, the terminal decline rate soon controls the production rate. The EUR cannot be accurately estimated for an individual well from the initial (first 12 months) production because the time series is insufficient to evaluate the nature and impact of the terminal decline.

Physics Based Model

We used a physics-based, black-oil model from Male (2019) and Male et al. (2017), modified from the work of Patzek et al. (2013), to estimate future production. Male (2019) tested the validity of this model by hindcasting production for the Bakken, Permian basin, and Eagle Ford and found acceptable accuracy.

This physics-based model is based on a rectilinear flow geometry in which hydrocarbon flows from a region of rock following a fixed cross-sectional profile, called the stimulated reservoir volume (SRV), into a series of evenly spaced, planar hydraulic-fractures. As reservoir fluids reach these fractures, the model assumes they are instantaneously transported to the surface. A finite-differences solver is used to calculate the recovery factor over scaled time, where time is divided by the characteristic time-to-BDF.

The outputs of these physics-based models are then matched to monthly production histories reported from public sources. After matching, each well has an EUR and a characteristic time-to-BDF (tau), which is related to the time at which neighboring hydrofractures in a well begin to interfere with each other. A relation for this characteristic time is

$$\tau = d^2 / \alpha_i \qquad (1)$$

where *d* is half the distance between adjacent hydrofracture planes, and α_i is the hydraulic diffusivity of the hydrocarbon at initial reservoir conditions. Note that it is not necessary to know the half distance between fractures as this metric is embedded within a fit parameter in the physical model (see Male, 2019).

Two flow-regimes (transient and BDF) result from this model. These come from the underlying physics, and can be described through the Arps b-factor (Arps, 1945). During the transient flow period, the well drains oil from an increasing fraction of the SRV, production rate (q) scales as $q \propto 1 / \sqrt{t}$, and the Arps b-factor is above 1. After, the well is in BDF. In this flow period, the well is draining from the full SRV, and the b-factor settles at approximately 0. This corresponds to production rate declining exponentially.

Arps b-factors are part of an empirical approximation of production over time through the equation

$$q(t) = q_i / \left(1 + \frac{bt}{D_i}\right)^b \qquad (2)$$

where *q* is the production rate, t is time-on-production, q_i is the initial production rate, D_i is the initial decline rate, and *b* is the Arps b-factor. The transition time between regimes varies by reservoir fluid properties and pressure-temperature conditions. Bakken wells exit from transient flow around 0.55 τ.

After recovery factor curves were generated for appropriate reservoir and fluid conditions, they were fit to cumulative well production over time. Production in the Bakken is reported monthly. The fitting parameters are the mass of oil in the SRV (M) and τ. For wells in BDF, τ can be determined uniquely from the production fit, but for wells in transient flow there is an unresolved degeneracy and an infinite number of (M, τ) combinations could match production. For those wells, each well has an age less than or equal to 0.55τ, i.e. τ is constrained to 1/0.55 of the well age (see discussion in Male, 2019). We take wells that are in transient flow and assign τ as the greater of 1/0.55 of the well age and the median time-to-BDF for the full population of wells.

EUR is calculated by using the physics-based recovery factor curve fits to forecast production rate from the end of production history to 20 years, then adding the cumulative produced already to the forecasted production.

Terminal decline rates are calculated numerically, by taking the smallest year-on-year decline from years 10 to 20 for each well's production forecast. The lower bound terminal decline rate is 5% per year for wells in transient flow at 20 years, and terminal decline rates can be greater than 50% for wells that entered BDF in their first two years of production.

Statistical Analysis of the Dataset

Exploratory data analysis was performed on the completion and production metrics. Completion data was aggregated by the month that each well was completed, and the average and 95% confidence intervals for these parameters were calculated. Because the data were neither stationary nor normal, confidence intervals were estimated at the 95% confidence level using basic bootstrapping. Production metrics were plotted through the same method, aggregating by the month each well began producing.

Results

The results of our data analysis are shown in Figure 1 (completions change over time) and Figure 2 (production changes over time). From 2007-2018, wells grew longer and had much more intensive completions (Figure 1). Productivity did not increase in commensurate magnitude (Figure 2).

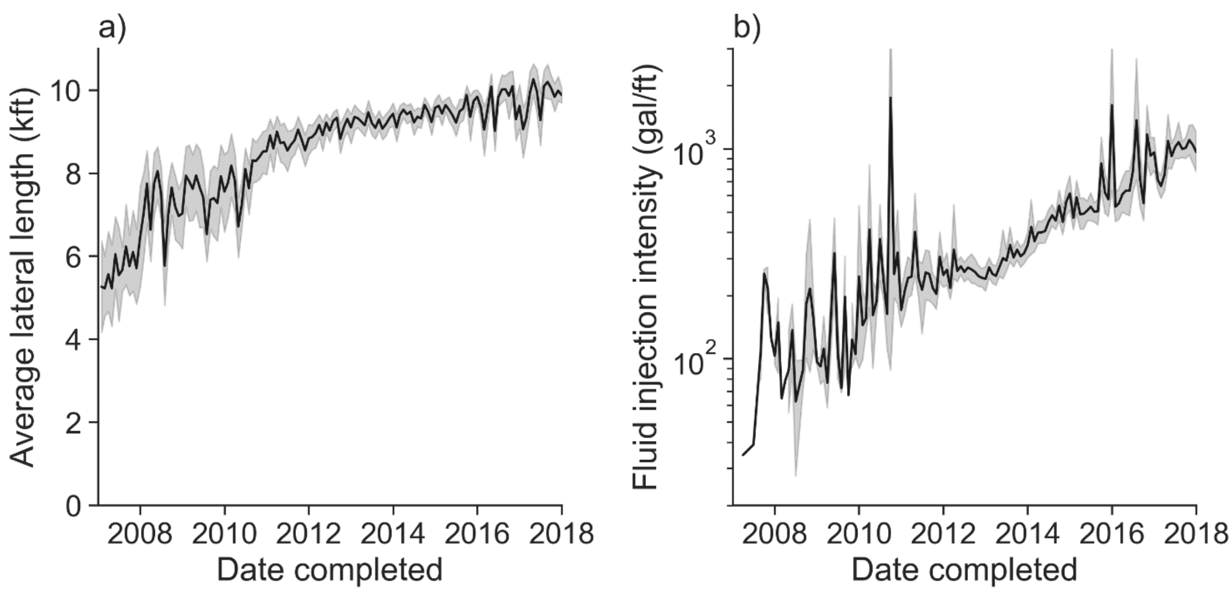

Figure 1 Changes in well completion metrics over time. The average length of laterals (**1a**) increases from approximately 5 kilo-feet prior to 2008 and 10 kilo-feet after 2008.The fluid injection intensity (**1b**) shows and general increase from 2008 to 2017. Shading indicates the 95% confidence interval in the mean, calculated through bootstrapping.

The increase in the length of horizontal wells over the study period (Fig. 1a) shows the average well in 2007 was 5,000 ft in length, jumping to ~9,000 in 2008, and has increased very slowly through 2018 to ~ 10,000 feet. The relative fracture intensity can be estimated by the volume of fluid injected per length of lateral (Fig. 1b). This metric shows an exponential increase from 2012 through 2017.

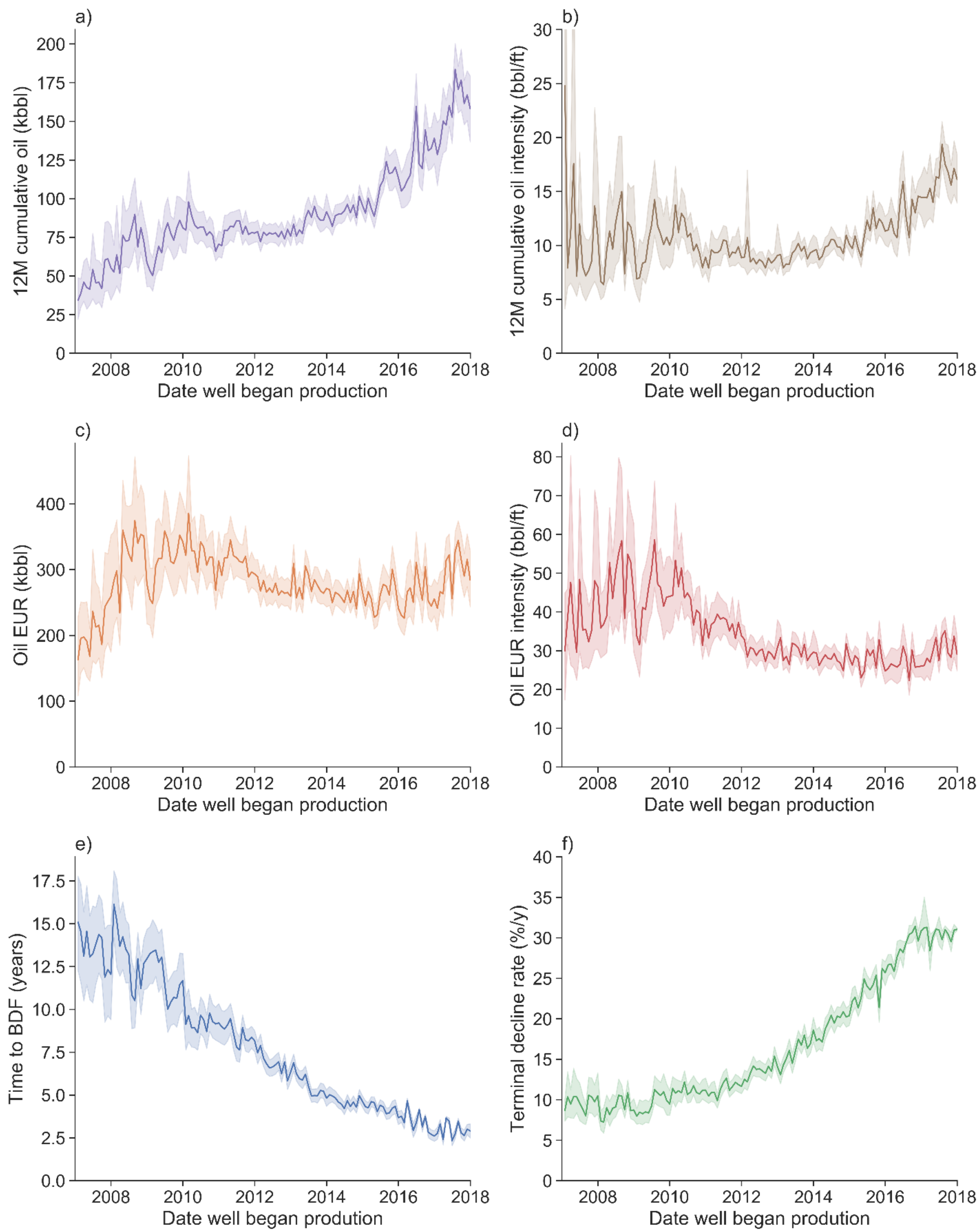

Figure 2. **Trends in production related metrics.** The 12-month cumulative oil production (**2a**) shows an approximately

constant average value from 2010 to 2013, followed by a steepening rate of increase from 2014 to 2018. Normalizing the 12

Month cumulative production by the length of the lateral (**2b**), results in an approximately constant value from 2011 to 2015, followed by an increase of approximately 50% from 2015 to 2018. The EUR for oil (**2c**) shows a general small decrease from 2010 to 2017. However when normalized to the length of the lateral (**2d**) a decrease is only apparent from 2010 to 2013. Subsequently EUR are approximately constant. Time-to-BDF (**2e**) and TDR (**2f**) distributions for wells. Note that the time to BDF has decreased, in a linear fashion, from approximately 15 years in 2008 to three years in 2018. The TDR, roughly constant from 2008 to 2011, has increased from 12% per year in 2012 to 33 % per year in 2017. The shaded areas show 95% confidence intervals calculated through bootstrapping.

The 12-month cumulative oil production (a metric favored by operators), shows an accelerating increase with time from 2006 through Q1 2018 (Figure 2a) with a more regular pattern of increasing rate from 2012 to 2018 (and a dramatic increase of approximately 50% from 2015 to 2018). Normalizing these values to the length of laterals lessens the rate of increase. As shown in Figure 2c the EURs (estimated from our physics-based scaling approach) have decreased from 2009 to 2016, and have been approximately constant from 2016 on. The same pattern, in a more subdued form, can be seen in the EURs normalized for length of lateral (Fig.2d).

The time to BDF and the TDR of the wells is shown in Figures 2e and 2f. These plots show clear trends. As fracture intensity increased over time (from 2008 to 2017) the time to BDF for the median well has decreased from 16 years to 3 years. During the same time period, the terminal decline rate has increased from 8% to 31% per year.

Discussion

Over the last decade, tight oil operators in the Bakken play have dramatically increased initial production from their wells. This has been widely interpreted as reflecting an equivalent increase in the EUR of these wells. These increases in 12-month cumulative-production (typically used as a metric for IP), show a very general correlation with the increased fracture-water intensity in Figure 1b and, at face value, appear to support the operator's apparent belief that their application of improved technology is increasing the ultimate oil recovery from these wells.

In a widely quoted paper, Covert (2013) estimated that Bakken wells "fracked in 2005 are actually 13.7% more productive than wells fracked in 2006". However, he noted that "the confidence interval around this estimate is wide enough to include zero." Then, he concluded, "wells fracked in later years are significantly more productive than wells fracked in 2005 or 2006." For example, wells fracked in 2009 are 35.6% more productive. As is shown in Figure 2a the 12-month cumulative production (our measure of initial production or IP) increases from 2007 to 2009, however when normalized to length of lateral this increase is erased. As Covert (2013) appears to have used 12 month cumulative oil production normalized to the length of the wells lateral as the metric for oil production it was not at first clear why the trends found by Covert were so different to the trends shown in Figure 2. This could be due to selection bias, as Covert's data set of wells is one-fifth the size of our study.

Recall, from the Introduction, that Smith's (2018) model for ultimate recovery from the Bakken play has a built-in increase in "fracking efficiency" of 15% per year. Smith suggested that this increase was "roughly consistent" with Covert's (2013) "estimate of efficiency gains" as a result of operator's learning how to optimize strategies for proppant and fluid intensities. Smith assumed that "fracking efficiency" increased during this time period at an even higher rate. Apparently, he based this on the idea that many of these wells were being drilled in reservoir rocks of lower quality. He concluded that these wells "are understood to have achieved high IP rates" than expected. These higher rates he saw not as the result of higher quality reservoirs or presumably higher oil saturations, but rather because "they benefitted from the cumulative effect of rapid learning." By this, Smith meant that companies learn from one another about how to increase IP of wells (efficiency gains in Smith's parlance) by finding optimal weights of proppant and volumes of fracking fluid to inject. On this basis he estimated that efficiency was increasing about 20% annually.

In the context of the analysis of the data presented in this paper Smith's conclusions are inconsistent with the trends presented in the Results section. The time period studied by Covert (2013) and Smith (2018) does correspond to the general increase in 12 month IP shown in Figure 2a. However, the EURs (estimated from our physics-based scaling approach) decreased from 2009 to 2016 and have remained approximately constant from 2016 on (Figure 2c), The same pattern can be seen in the EURs normalized for length of lateral (Fig.2d). Significantly, the average, length-normalized EURs decreased from 2009 to 2015. These trends correlate with a general increase in the water to oil ratio that is best interpreted as a decrease in the average reservoir quality. This may not be generally applicable to tight oil plays as a significant portion of the oil in the Bakken has in some part migrated towards structural highs and the water saturation reflects this tendency (Theloy, 2014).

To understand how 12-month cumulative oil production or IP can be increasing while EUR is constant or decreasing, we explored a number of possible explanations. The relationship between time to BDF and the TDR of the wells is of key interest because the shorter that time to BDF and the faster the subsequent decline rate the more rapidly oil production decreases below the initial production. The plots of these metrics show clear trends (Figures 2e and 2f). The change in the time of onset of BDF and the magnitude of the subsequent decline rate (TDR) is dramatic. One measure of the intensity of hydraulic fracturing is the volume of fracture fluid pumped per length has increased over time (from 2008 to 2017). This corresponds with the median time to BDF decreasing, consistent with faster drainage of oil from the fractured volume. Over the same time period the decline rate (TDR) increased. This decrease was so large that it has triggered numerous articles in oil and gas industry magazines, as noted in the Introduction. What has not been recognized prior to this study is that the increase in decline rate that is positively correlated with higher IP measured by the 12-month cumulative production.

In his recent study, Smith (2018) assumed that wells drilling in the future would have a constant ratio of EUR to IP. Smith (2018) did suggest, "a potential negative correlation between IP and the subsequent decline rate" is a factor that "cannot be ruled out." Despite this qualifier, Smith used the assumption of constant EUR:IP ratio in his projections of future production from the Bakken. Smith viewed the increase in "fracking efficiency" is likely to continue to increase and to "raise the volumes of… oil that operators are able to extract from the remaining sites."

Attanasi and Freeman (2019) conclude that a significant part of increases in well productivity from 2010 to 2015 was the consequence of operators "high grading" drill sites or, in their words, "improved well site selection." However, our analysis of the data does not support this conclusion. The EUR and lateral length normalized EUR decrease from 2010 to 2015, inconsistent with Attanasi and Freeman's claim that operators were high grading available drilling sites, which would have led to higher EURs.

According to our analysis, the very strategies that operators have pursued in order to increase initial production (larger completions, more hydrofracture stages) have also resulted in accelerating boundary-dominated flow and increasing terminal decline rates. Therefore, increases in IP can be achieved by increased fracturing intensity with minimal change in the length-normalized EUR. This explains the apparent paradox outlined in the Introduction. Our analysis is clearly inconsistent with the ideas presented by Covert (2013) and the conclusions of Smith (2018). The data and analysis presented in this paper is inconsistent with Smith's assumption that ratio of EUR to IP is constant.

Even with a constant EUR, increasing IP can improve the economic value of a well. This is because the Net Present Value (NPV) of the well may be higher if there is a larger cash flow in the first few years. A shorter payback period (the time needed to pay off the cost of infrastructure), leads to a more profitable well.

Most previous analyses of oil production-decline-curves for Bakken wells have used 12-month cumulative production as a proxy for EUR. This approach is likely to generate significantly erroneous results because it does not take into account the changing long-term decline rates. Our approach, utilizing our physics-based model for estimating EURs Male (2019), provides a robust basis for understanding the nature of the decline in production hydraulically-fractured tight oil wells. Because completion designs for tight oil wells are similar across basins and these wells target low permeability reservoirs, this approach can be applied to all tight oil plays.

Conclusions

The contribution that tight oil will make to future US oil production is a controversial subject, with vigorous arguments being made by proponents for both views. This study has demonstrated that the assertions of both sides of the argument are inconsistent with rigorous, physics-based analysis of the well production data. Over the last 16 years, the initial production of Bakken wells has increased as reported by industry and modeled by Covert (2013) and Smith (2018). The increase in early production has resulted from operators increasing the fracture intensity. of completions. This is consistent with the assertions of operators in the Bakken play. At the same time as the median initial production of Bakken wells increased (by as much as 100% from 2014 to 2018), their estimated ultimate production (EUR) remained broadly constant.

The results of this study provide a framework for understanding the mechanisms controlling both initial and long-term production from horizontal, hydrofractured wells. The analysis presented in this paper demonstrated that:

(1) Fitting ad-hoc functional forms (such as Arps, 1945) to the production data from these wells is unlikely to enable meaningful extrapolation to time periods beyond the age range of the data.

(2) Using metrics such as the 12-month cumulative oil production (favored by operators) as an analogue for EURs, as has been done in most all machine learning analyses of shale oil productivity, results in erroneous results. Overestimates of long-term productivity for recently drilled wells, of 50 to 100% are likely when EUR estimates are based on IP.

(3) Over the last 10 years, the average EUR for new Bakken wells has remained largely constant and actually decreased from 2010 to 2017. The average, length-normalized EUR decreased from 2009 to 2015. These trends correlate with a general increase in the water to oil ratio that is best interpreted as a decrease in the average reservoir quality.

(4) The changes in 12-month cumulative production (IP) over time are not strongly correlated with the EURs of wells.

(5) Estimates of the future production of tight oil plays based on an increase in technically producible oil, due to increasing initial production, result in significant errors.

(6) The data do not support published claims that annual productivity of new Bakken wells has been increasing in the range 10 to 20%. The data also do not support a published claim that the EUR to IP ratio of wells is constant.

(7) Our analysis of decline curves of Bakken wells resolves the paradox detailed in the Introduction to this paper, and provides a robust basis for forecasting future US oil production from tight-oil basins.

The results of the current study resolve the apparent discrepancy between: (a) operator's claims of large increases in well productivities; and (b) analysts claiming that long-term production of these same wells may be significantly lower than expected. For the Bakken, implementation of more closely spaced, intensive fracturing results in higher initial production and steeper terminal-production declines. Critics focus on the higher terminal-decline rates whereas operators trumpet the higher initial production. These are not mutually exclusive, but their analyses do not incorporate an understanding of the nature of production from multi-stage fractured horizontal wells as expounded here. The overarching conclusion that arises from this study is that none of the advances in completion technologies, which are in widespread usage, are increasing the EURs of tight-oil wells. This conclusion is important in the context of estimating the total reserves for tight oil plays and thus for predicting future US oil production. Published estimates that optimization of completion strategies has resulted in 10 to 20% increases in the lifetime productivity of multi-stage fractured wells, are not supported by the analysis of the large production data base presented in this paper.

The over-arching conclusion of this study is that the ultimate recovery of oil from tight oil basins should not be based on initial production. Estimates of ultimate long term production or EURs, should not be scaled –up to take into account future increases in IP related to increased intensity of hydraulic fracturing. This conclusion should be taken into account in any estimates of future tight-oil production. It places limits on the future contributions of tight oil to the energy production of North America (and globally). This will be critical to any attempt to make robust estimates of future production from tight-oil plays and hence future global-oil production must take our findings into account.

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