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Blinking Out: North Dakota without capital for replacing production

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Introduction

Unlike conventional wells which, once drilled, sometimes produce for ten or twenty years without significant overhaul, wells in North Dakota often have a short economic run. Producers must constantly drill, fracture and lift to keep production steady. In a climate of very low oil prices where one well cannot quickly pay itself off and finance the next, capital needs to be continuously raised to keep a lease going. The central question addressed in this paper is: what would happen if the money supply dried up and the state and its producers were faced with the prospect of no more capital to drill? How long would current production last? Would some producers or counties fare better than others? And finally, once shut in, what would be the investment necessary to bring production back up?

Knowing how production will decline in the face of no new investment should be of paramount importance to anyone passively dependent on its revenues, such as royalty owners, state and civic governments, lien holders and non-operating production partners. Few of these parties have a say in if or how capital is deployed, yet all have an interest in knowing how revenues are likely to drop in a worst case scenario. Instead of confronting the unique production requirements of unconventional wells, people still tend to think and plan in terms of metrics that make sense in a world of assets that depreciate slowly. The usual ways of talking about production are in terms of *flowing barrels per day of oil equivalent* (boepd) and *total reserves*. In places like North Dakota, it might be more productive to think of an asset in terms of flowing barrels and *half-life*. "Half-life" here is defined exactly as it is in chemistry: the amount of time it will take before boepd is half of the amount it is currently. Equivalently, it is the amount of time over which half of the production in play must be replaced in order to keep overall production steady. This metric can be applied to a single well, a group of wells owned by a particular entity, or an entire county, state or nation. Although analysts often work with decline rates and show graphs of the rise and fall of oil fields, the half-life of a project is very rarely reported.

This failure to adopt a half-life mentality is unfortunate, because it throws a number of common observations into question. For example, studies estimate the decline rate of mature OPEC wells at around 5% (Höök, 2009). Saudi Arabian wells could be declining as little as 2% per year. These numbers give half-lives of 13 to 34 years. If the Saudi well count is estimated at about 5,000 onshore wells, this means that less than 100 new wells a year will keep production stable (assuming no significant reservoir depletion occurs over the next three decades). In contrast, most US shale wells decline at rates greater than 50% early in their lives and finish at rates of 8 to 15%. The half-life of a well declining at 50% is about 1.3 years, and there are shale wells in the USA that decline even more quickly than that. Once a well has reached its 8% mark, its half-life is 8.5 years, but it must be remembered that overall production is a mix of young and older wells. The young wells, with higher production, are likely to dominate the overall decline. In any case, replacing production in the USA requires an obvious and large capital investment.

In this study, monthly production forecasts were made through 2030 for every active well in North Dakota. To make the numbers more intuitive, a series of movies were made showing production ramping up from 2000 to its peak in 2015 and then beginning to decline as the price of oil falls and rig counts decline. The last date of actual production records for most of the wells is March, 2016. After that, production volumes are forecast through 2030 as if no new production were brought online. The primary conclusion of the study is that, without investment, the half-life of production in North Dakota is about 3.3 years. Monthly production volumes for every well are represented by the size of markers on the map. Uncertainty in the forecast is represented by their color saturation. As wells age, they get smaller and the uncertainty in their forecast tends to go up. Visually, they appear to "blink out."

Method

To conduct this study, we needed to forecast production volumes for every well in the state of North Dakota, including an estimate of uncertainty. Since the total well count is over 13,000, it was essential that the forecasts be made automatically. The vast majority of North Dakota wells are hydraulically fractured shale wells, many of which are on artificial lift and a number of which have had re-fracture jobs. There are a number of older conventional oil and gas wells, some with multiple stages and comingled zones. Artifacts abound, including missing data, unrecorded shutins, erroneous recordings and inconsistent allocations. In order to do the study, it was absolutely essential that the forecast algorithm not get confused by any of these issues and be capable of producing a reliable forecast for every well in the dataset without the need for human intervention or heavy data cleaning. The BetaZi (BZ) physio-statistical engine for automatic stochastic production forecasting proved ideal for this application (Kuzma et al, 2014).

The BZ engine (or "BZ Machine") uses an Open Universe Bayesian Network Generative Model to forecast oil and gas monthly volumes based on oil, gas and water historic monthly volumes and working days (when recorded). The resulting forecast is reported in percentiles (p1 through p99; by convention, production has a 99% chance of exceeding the p99). The most important percentiles are the p90, p50 and p10. 90% of actual production volumes are expected to exceed the p90; 10% are expected to exceed the p10; and the p50 is the median forecast. For this study, forecasts were cut off when monthly volumes fell below 30 bbl/mo or 90 mcf/mo for gas. No terminal decline was enforced (although it is possible to do so using the BZ Machine). A complete set of forecasts were made twice: once using data that was current through 3/1/2016 and once in "holdback mode," as if it were 3/1/2013. The second run was made to assess the performance of the engine.

The total number of wells for which forecasts were made was 13,071, with the last production data used being from March, 2016. The data was drawn from Tobin Insight based on North Dakota public records. Including setback forecasts, about 26,000 forecasts were computed over roughly 170 hours on a remote server with four cores. The resulting dataset was distilled into p50 monthly production volumes (historical and forecast) and corresponding normalized uncertainty computed as (p10-p90)/p50. Such a compression from 98 percentiles per well per month to just two numbers per well per month was necessary in order to load the dataset into the Spotfire desktop application for analysis.

Results

Individual well forecasts

Figure 1 shows two examples of forecasts which would have been difficult to make without the BZ Machine. The figures in the left column are in holdback mode and the figures on the right are in full forecast mode. The first row (a,b) shows a well with relatively short history in McKenzie County. The well in the second row (c,d) has been producing since 1956 in Williams County. It's notable that the uncertainty on both wells in both modes is roughly 1.5, meaning that for both wells uncertainty is not primarily a function of the length of available production history. For the McKenzie well, it is likely because there have been several shutins. For the Williams well, the water cut is steadily increasing and there is high variance on production volumes. The McKenzie well

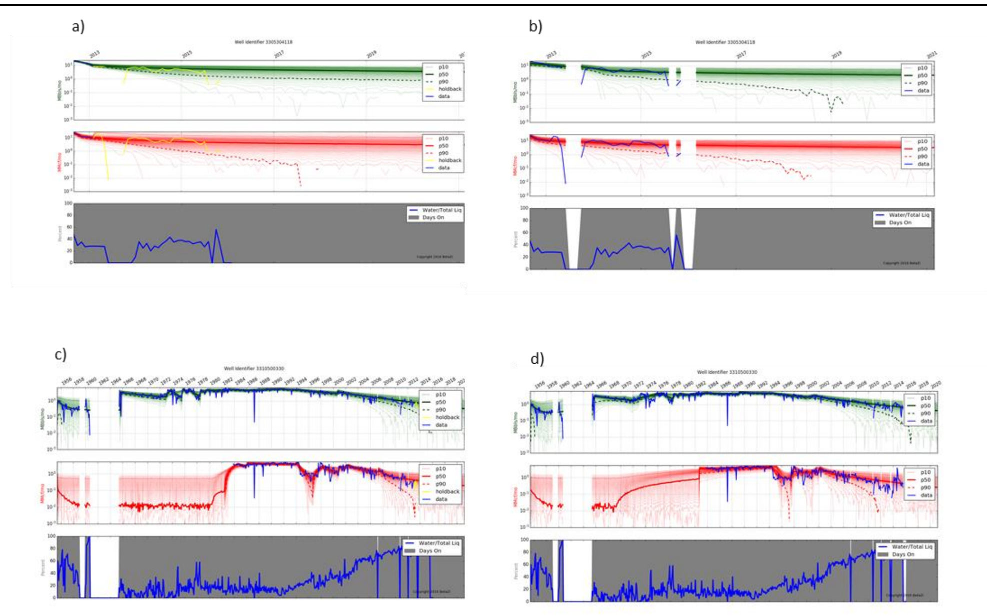

Figure 1: a) McKenzie County short production well holdback forecast; b) full forecast; c) Williams County long production well holdback forecast; d) full forecast.

is also interesting because there was a sharp increase in gas production in 2013 that was predicted by the p10 in holdback mode. One of the features of the BZ Machine is that it often predicts sharp increases in production for an otherwise flat or nearly flat producing well by postulating that production is being artificially restricted (usually by means of a choke back). Images such as these were produced for all of the wells in the study, including a number of currently inactive wells.

Monthly p50 production volumes were loaded into Spotfire for all months between 1/1/2000 and 1/1/2030 and plotted with the size of a marker proportional to its p50 (BOE and oil) and color intensity proportional to its uncertainty (BOE in red, oil superimposed in green). Figure 2 shows snapshots taken January 1 every five years from 2005 through 2030. Wells are hidden when their p50 production is lower than 30 bbl/mo or 100 boe.

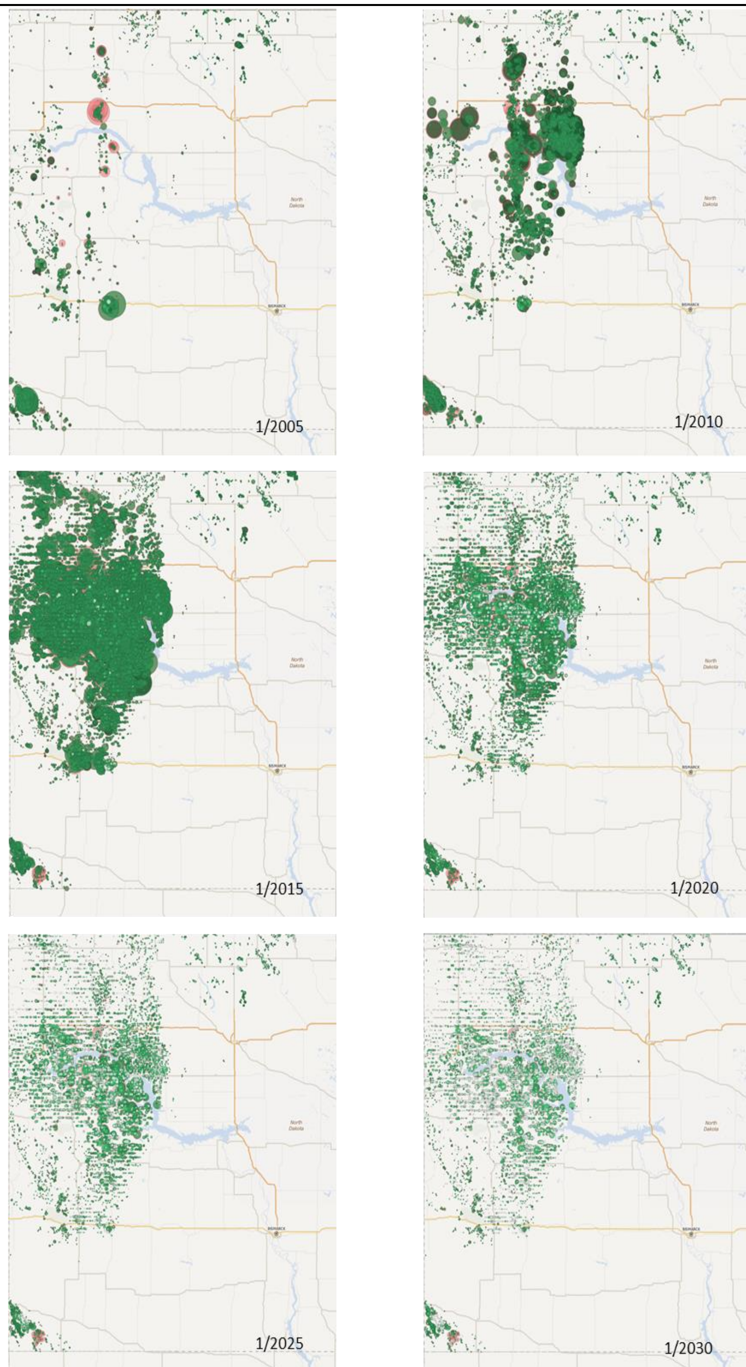

Figure 2: Frames from the Bakken Blinking Out Movie showing production in terms of boe/month (red) with superimposed oil in bbl/mo (green). Color saturation indicates normalized uncertainty with dark being more certain.

Half-life

According to this analysis (and state records), peak production for the state of North Dakota occurred in June, 2015 (about 43 Bboe). The half-life of all wells in the state is estimated at 3 years 4 months, which will be reached in October, 2018: 40 months from now. This is a sobering figure considering that the number of wells producing at the state's peak just over a year ago was almost 12,400. A back-of-the-envelope projection suggests that replacement would require 6200 wells, or 1860 new wells a year for three years. The total number of new wells drilled through to March 2016 was only about 600. According to https://www.dmr.nd.gov/oilgas/riglist.asp, the active rig count in May, 2016 in North Dakota was 28, making the state's operators capable of drilling between 650 and 700 new wells a year. It only takes a glance to realize that the capital investment required to bring state production back up to 2015 levels would be enormous, and well beyond any amount justified by global oil pricing. It is, of course, similar to what was required to double production between May, 2012 and June, 2015 when 6114 new wells were opened. The curve in Figure 3 has close resemblance to the classic Hubbert curve showing the production of an oilfield as it is discovered, matures and depletes. Only in this case, depletion might be a function not of the asset but of the capital needed to exploit it.

All of the wells in the study do not have the same decline rates. The older (and presumably more conventional type) wells which were producing in 2000 only declined by 12% between June 2015 and October 2018. It would be reasonable to assume that operators whose assets are dominated by this type of well would have production half-lives that are considerably longer than operators of shale wells. Indeed, Petro Harvester Operating Company, LLC, who operate 156 mostly conventional wells near the Canadian border in Bottineau, Burke and Renville counties do not reach their half-life before 2030 according to our forecasts (http://petroharvester.com/operations/northern-business). In contrast, the life of the 1,300 wells operated by Hess Bakken Investments II Inc. mirrors that of the state, peaking in August 2015 and hitting its halfway point quite soon, in October, 2017.

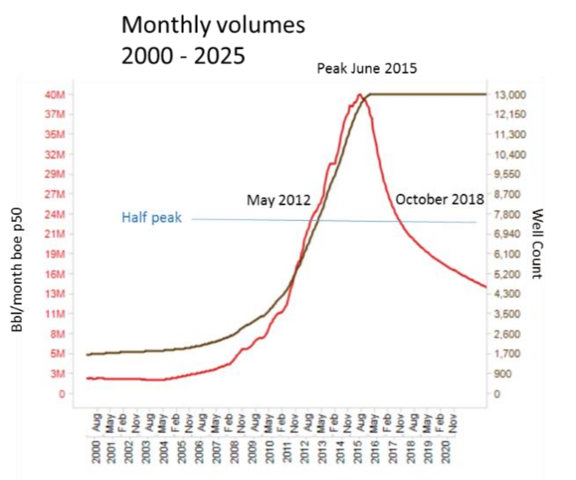

Figure 3: Chart showing monthly p50 volumes and well count.

Hyperbolic Fit

Almost all production forecasting is done using a hyperbolic equation. The BZ Machine does not use this but sometimes produces forecasts that are hyperbolic in character. Engineers frequently discuss the proper value for the "formation factor," *b*, in the equation:

$$q = \frac{q_0}{(1+D_i bt)^{1/b}}.$$

q is the production rate at time t, q_0 is initial production and D_i is an initial decline rate. Often the equation is fit in piecewise fashion so that initial production and decline are measured at the start of a segment. It is thought that typical acceptable values for b in North Dakota Shales are between 0.5 and 0.8, and there is controversy about using formation factors greater than 1. Nevertheless, when the hyperbolic function is fit to the forecast production from April 2016 onward, it is almost impossible to do so using parameters that fall within ranges that petroleum engineers would recognize. The best fit parameters are q0 = 2.9 x 107 (approximately the rate of production, Di=0.035 and b=1.8). Those parameters yield the curve shown in Figure 4. A *b* factor of

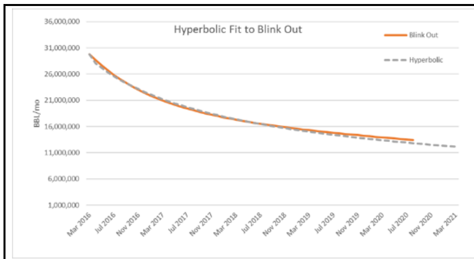

Figure 4 : Shows the forecast decline after present on a log scale with a best fit hyperbolic curve.

1.8 raises eyebrows, but the fact that it is difficult to model the decline otherwise points out that the hyperbolic equation may not be the most appropriate equation for modeling decline in North Dakota shales.

Conclusions

It is unlikely that North Dakota production will collapse as fast as the charts show here; investment and drilling continue albeit at much reduced rates compared to what they were in 2014. It is, however, unsettling to realize how fast it could fall in the event of a crisis such as a liquidity crunch or a very long period of low prices. Although the entire state may not face such catastrophe, it is more than likely individual owners will. There is very little cushion for operators who are unable to raise money to replenish production unless they are producing from conventional reservoirs.

The oil and gas industry is accustomed to talking about reserves in terms of the total amount of hydrocarbons “down there” and how many of those can be recovered. This study shows, however, that thinking about production in terms of its half-life underscores the crucial dimension of time in reserves analysis. Although concepts of reserves and recovery are central to the job of the petroleum engineer who must do his or her best to optimize them, the time factor is even more critical to economic evaluation than it is to management of operations. Undoubtedly, good engineering can improve the depletion rate of a well; however, it is just not possible for even the best engineering to move the half-life of a shale well into the realm of the half-lives of conventional wells. Production in North Dakota is, by its very nature, a short-term game.

Acknowledgements

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