DRILLING DEEPER

A REALITY CHECK ON U.S. GOVERNMENT FORECASTS FOR A LASTING TIGHT OIL & SHALE GAS BOOM

PART 2: TIGHT OIL

J. DAVID HUGHES

post carbon institute

Part 2: Tight Oil

PART 2: TIGHT OIL - CONTENTS

PART 2: TIGHT OIL - FIGURES

PART 2: TIGHT OIL - TABLES

2.1 INTRODUCTION

2.1.1 Overview

The widespread adoption of hydraulic fracturing ("fracking") and horizontal drilling in the United States to extract oil and natural gas from previously inaccessible shale formations has been termed the "shale revolution." In just the last few years, U.S. oil production—universally held to be in terminal decline a mere decade ago—has grown rapidly and significantly thanks to oil produced from shales ("tight oil"). The U.S. Energy Information Administration (EIA) now projects domestic oil production to reach the previous 1970 peak of 9.6 million barrels per day (MMbbl/d) by 2019 and decline gradually to 7.5 MMbbl/d by 2040.[1]

The environmental, health, and quality of life impacts of shale development have stoked controversy across the country. In contrast, the expectation of long-term domestic oil abundance—driven by optimistic forecasts from industry and government—has been widely reported and little questioned, despite the myriad economic and policy consequences.

This report investigates whether the EIA's expectation of long-term domestic oil abundance is founded. It aims to gauge the likely future production of U.S. tight oil, based on an in-depth assessment of actual well production data from the major shale plays. It determines future production profiles given assumed rates of drilling, average well quality by area, well- and field-decline rates, and the estimated number of available drilling locations. This analysis is based on all drilling and production data available through early- to mid-2014.

The analysis shows that U.S. tight oil production cannot be maintained at the levels assumed by the EIA beyond 2020. The top two plays, which account for more than 60% of production, are likely to peak by 2017 and the remaining plays will make up considerably less of future production than has been forecast by the EIA. Rather than a peak in 2021 followed by a gradual decline to slightly below today's levels by 2040, U.S. tight oil is likely to peak before 2020 and decline to a small fraction of today's production levels by 2040. The analysis also underscores the amount of drilling, the amount of capital investment, and the associated scale of environmental and community impacts that will be required to meet these projections. These findings call into question plans for crude oil exports and highlight the real risks to long-term U.S. energy security.

[1] Per the EIA's "reference case" in *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

2.1.2 Methodology

This report analyzes the top two U.S. tight oil plays—the Bakken and the Eagle Ford—in depth, followed by an assessment of five additional tight oil plays that make up most of the balance of the EIA's tight oil forecasts in its 2014 Annual Energy Outlook (AEO 2014).

The Bakken and Eagle Ford are investigated in depth as they account for nearly two-thirds of U.S. tight oil production and now have an extensive drilling history with which to assess key parameters; the report develops projections of their likely production levels given various scenarios of drilling and investment. The other tight oil plays are assessed based on their drilling and production history in comparison to the EIA forecasts of future production; they differ from the Bakken and Eagle Ford in that most of them have a long history of conventional oil and gas production stretching back decades. In total, all these plays account for 82% of the 2014-2040 tight oil production in the EIA's reference case forecast, and hence provide a solid basis for assessing its credibility. The remaining 18% comes from a number of smaller plays whose ultimate contribution remains highly speculative.

The primary source of data for this analysis is Drillinginfo, a commercial database of well production data widely used by industry and government, including the EIA.[2] Drillinginfo also provides a variety of analytical tools which proved essential for the analysis.

A detailed analysis of well production data for the major tight oil plays reveals several fundamental characteristics that will determine future production levels:

1. **Rate of well production decline:** Tight oil plays have high well production decline rates, typically in the range of 80-85% in the first three years.

2. **Rate of field production decline:** Tight oil plays have high field production declines, typically in the range of 40-45% per year, which must be replaced with more drilling to maintain production levels. This compares to field declines in the range of 5-6% per year in major conventional oil fields.[3]

3. **Average well quality:** All tight oil plays invariably have "core" areas or "sweet spots", where individual well production is highest and hence the economics are best. Sweet spots are targeted and drilled off early in a play's lifecycle, leaving lesser quality rock to be drilled as the play matures (requiring higher oil prices to be economic); thus the number of wells required to offset field decline inevitably increases with time. Although technological innovations including longer horizontal laterals, more fracturing stages, more effective additives and higher-volume frack treatments have increased well productivity in the early stages of the development of all plays, they have provided diminishing returns over time, and cannot compensate for poor quality reservoir rock.

4. **Number of potential wells:** Plays are limited in area and therefore have a finite number of locations to be drilled. Once the locations run out, production goes into terminal decline.

5. **Rate of drilling:** The rate of production is directly correlated with the rate of drilling, which is determined by the level of capital investment.

[2] See http://info.drillinginfo.com.
[3] IEA, *World Energy Outlook 2008*, http://www.worldenergyoutlook.org/media/weowebsite/2008-1994/weo2008.pdf.

The basic methodology used is as follows:

- Historical production, number of currently producing- and total-wells drilled, the split between horizontal- and vertical/directional-wells, and the overall play area were determined for all plays. Average well production decline for both horizontal and vertical/directional wells, and the average estimated ultimate recovery (EUR), were also assessed for all plays. For the Bakken and Eagle Ford, these parameters were assessed at the county- as well as at the play-level (the top counties in terms of the number of producing wells were analyzed individually, whereas counties with few wells were aggregated).

- Field decline rates and the number of available drilling locations were determined at the county- and play-level for the Bakken and Eagle Ford.

- First-year average production was established from type decline curves (i.e., average well decline profiles) constructed for all wells drilled in the year in question; 2013 was the year used as representative of future average first-year production levels per well. Average first-year production is used to determine the number of wells needed to offset field decline each year, and to determine the production trajectory over time given various drilling rates. In determining future production rates, the current trends in well productivity over time were considered; for example if recent well quality trends were increasing, it was assumed for plays in early stages of development that well quality would increase somewhat in the future before declining as drilling moves into lower quality outlying portions of plays.

- Projections of future production profiles were made for the Bakken and Eagle Ford based on various drilling rate scenarios. These projections assume a gradation over time from the well quality observed in the current top counties of a play to the well quality observed in the outlying counties as available drilling locations are used up. The different drilling rate scenarios were prepared so that the effect of a high drilling rate, presumably due to favorable economic conditions, compared to a low or a “most likely” drilling rate, could be assessed, both in terms of production over time and cumulative oil recovery from the play by 2040.

- Production history for all plays and production projections (in the case of the Bakken and Eagle Ford) were then compared to the EIA forecasts to assess the likelihood that these forecasts could be met.

- All plays were then compared to each other in terms of well quality and other parameters and an overall assessment of the likely long-term sustainability of tight oil production was determined.

Although public pushback against fracking due to health and environmental concerns has limited access to drilling locations in states like New York and Maryland and several municipalities, as well as triggered lawsuits, this report assumes there will be no restrictions to access due to environmental concerns. It also assumes there will be no restrictions on access to the capital required to meet the various drilling rate scenarios. In these respects, it presents a “best case,” as any restrictions on access to drilling locations or to the capital needed to drill wells would reduce forecast production levels.

2.2 The Context of U.S. Oil Production

2.2.1 U.S. Oil Production Forecasts

The EIA's *Annual Energy Outlook 2014* provides various scenarios of future U.S. oil production, as well as price projections and stated assumptions in terms of available technically recoverable reserves and resources, play areas, well productivity, and so forth.

Figure 2-1 illustrates the range of the EIA's oil production forecasts through 2040 compared to historical production. Most scenarios project the U.S. to meet or exceed its all-time peak production, which occurred in 1970. These scenarios assume cumulative production of between 77 and 123 billion barrels of oil between 2013 and 2040, which is 2.7-4.2 times the *proved reserves* (i.e., economically recoverable with current technology) that were thought to exist as of 2012.[4] Adding in *unproved resources*, which are uncertain estimates without price constraints, between a third and a half of remaining potentially recoverable oil in the U.S. will be consumed over the next 26 years according to the EIA projection. This amounts to the equivalent of 54-84% of all the oil produced over the 54 years between 1960 and 2013.

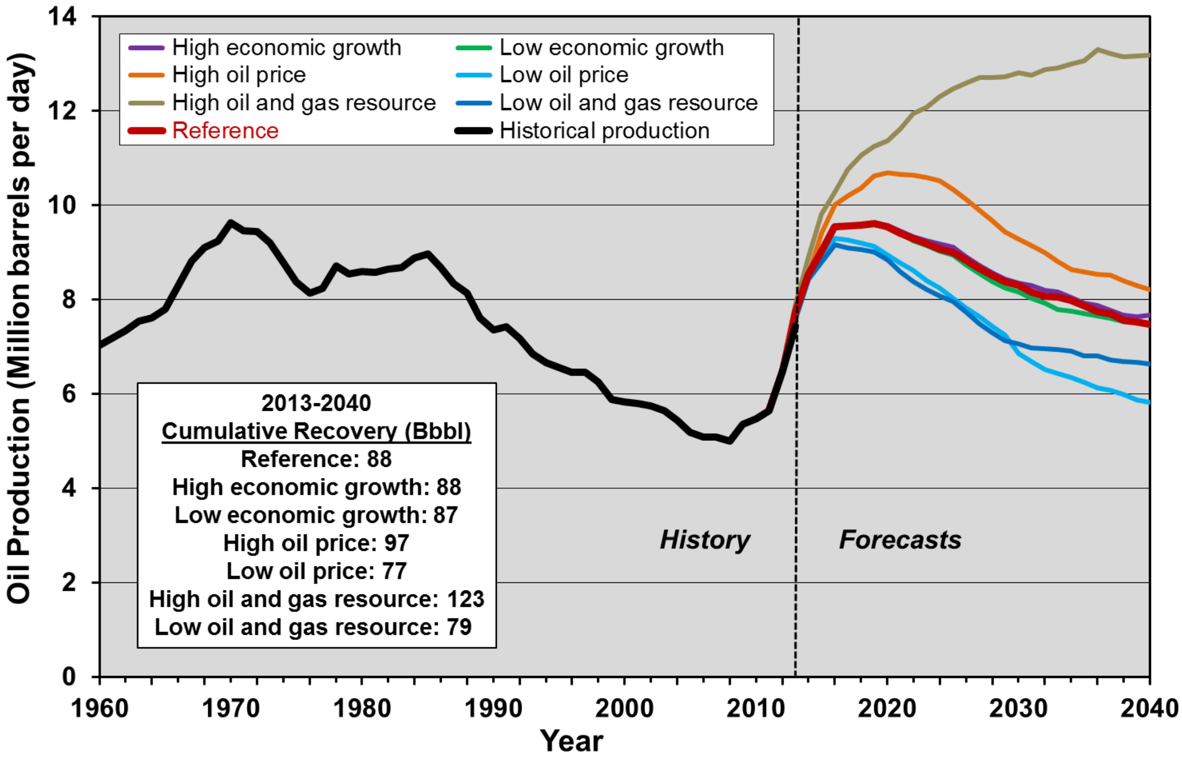


Figure 2-1. Scenarios of U.S. oil production through 2040 from the EIA's *Annual Energy Outlook 2014*,[5] compared to historical production from 1960.

Oil production includes both crude oil and lease condensates.

[4] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

[5] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

The source of this optimism in future oil production is the application of high-volume, multi-stage, hydraulic fracturing technology in horizontal wells, which has unlocked previously inaccessible oil trapped in highly impermeable shales and tight source rocks. Figure 2-2 illustrates the EIA's reference case projection for oil production by source through 2040. Although conventional production is forecast to be flat or declining over the period, tight oil production increases rapidly to a peak early in the next decade, amounting to roughly half of all U.S. oil production. Oil prices in this reference case are forecast to remain below $140 per barrel over the period. Notwithstanding talk of U.S. energy independence, this scenario implies that U.S. oil production, even with tight oil, will amount to only 40% of projected 2040 demand.

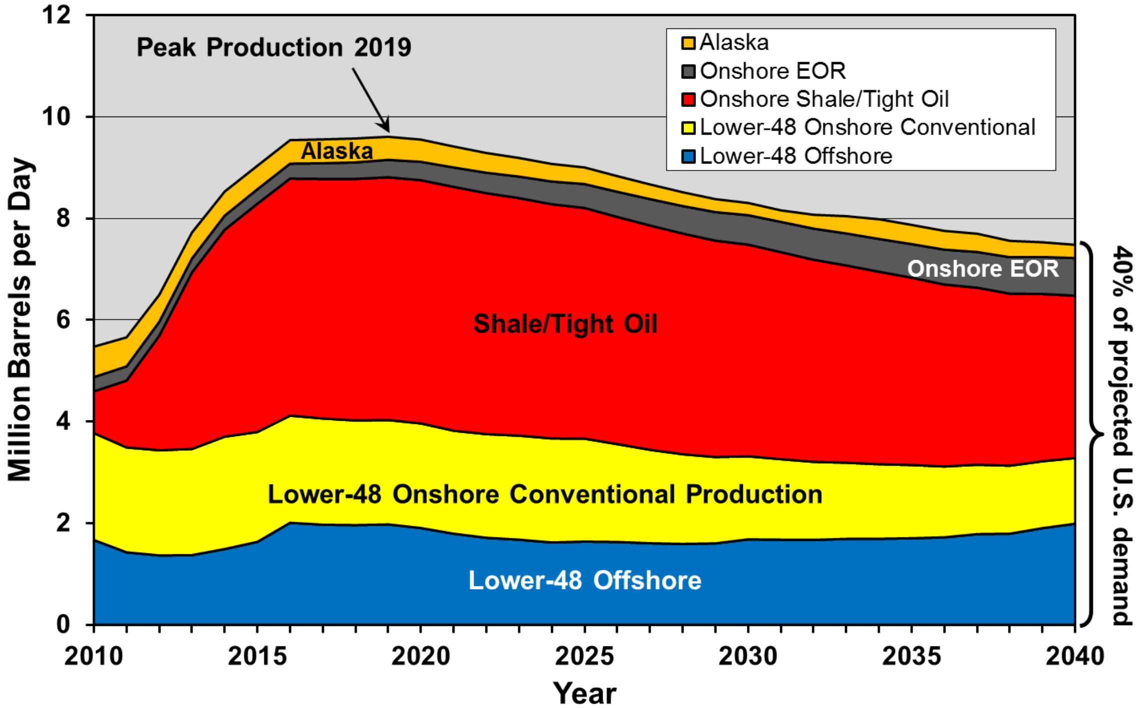


Figure 2-2. EIA reference case projection of U.S. oil production by source through 2040.[6]

[6] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo

Figure 2-3 illustrates EIA's projections for tight oil production in several cases. These assume the extraction of between 37 (low oil price case) and 47 billion barrels (high oil price case) by 2040. This amounts to all of the 7.15 billion barrels of proved tight oil reserves and between 50% and 67% of the EIA's estimated 59.2 billion barrels of unproved tight oil resources (unproved resources have no implied price required for extraction and are highly uncertain, as evidenced by the EIA's recent 96% downgrade of resources in the Monterey Shale of California[7]).

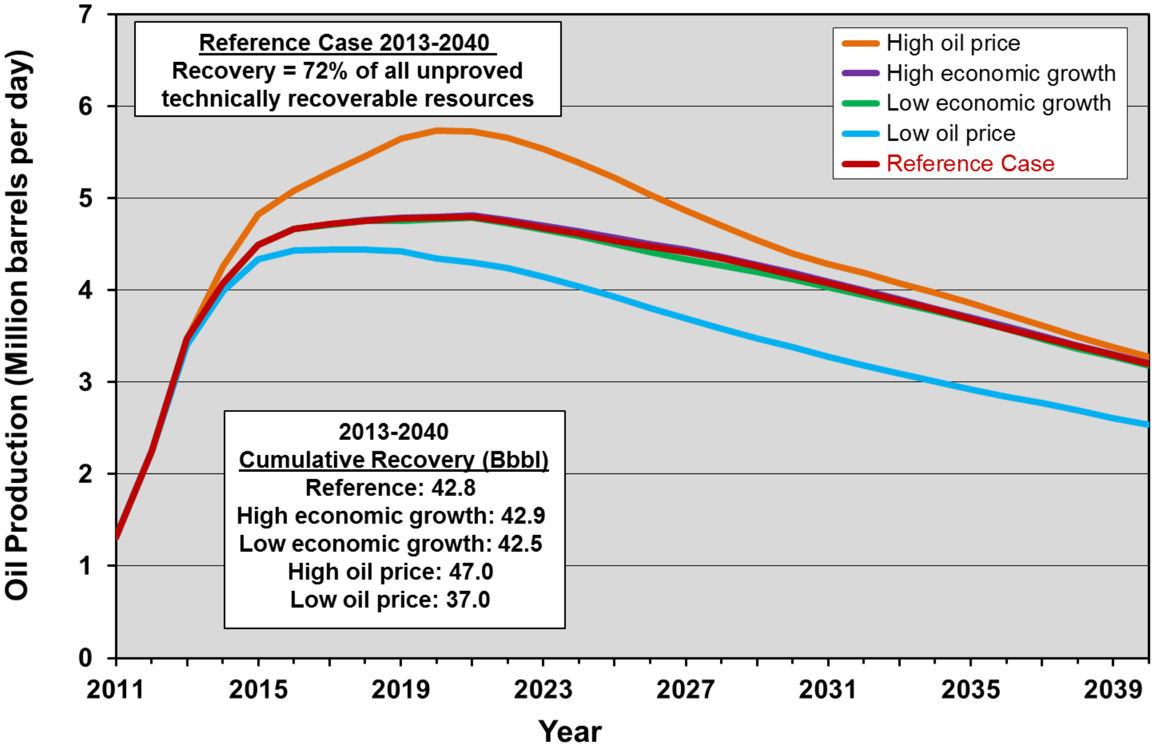


Figure 2-3. EIA scenarios of U.S. tight oil production through 2040.[8]

According to the EIA, proved reserves of tight oil are 7.15 billion barrels and unproved technically recoverable resources are estimated at 59.2 billion barrels, as of January 1, 2012.[9]

---

[7] Louis Sahagun, "U.S. officials cut estimate of recoverable Monterey Shale oil by 96%," *Los Angeles Times*, May 20, 2014, http://www.latimes.com/business/la-fi-oil-20140521-story.html.

[8] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

[9] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf

Figure 2-4 illustrates how the EIA reference case projections for tight oil production are divided between the Bakken, the Eagle Ford, and all other plays.

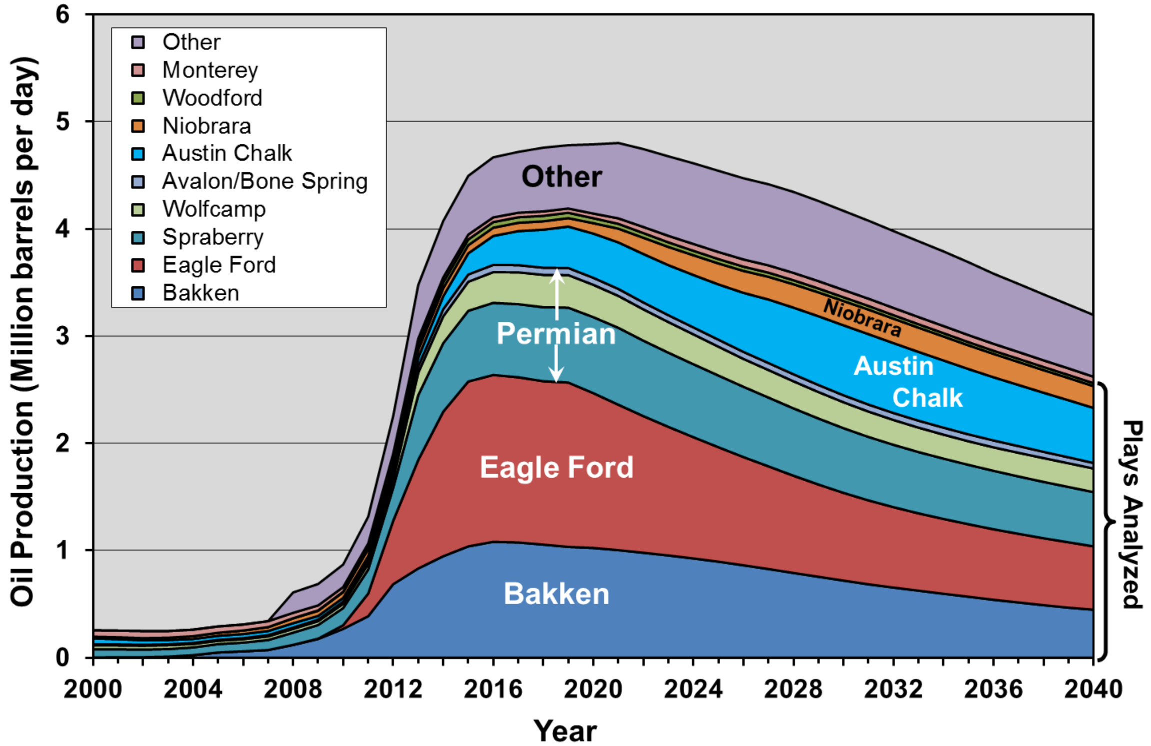


Figure 2-4. EIA reference case projection of tight oil production divided among Bakken, Eagle Ford, and all other plays, 2011-2040.[10]

This report analyzed the seven most productive plays, which account for 82% of EIA's tight oil production forecast to 2040.

The EIA reference case clearly expects the Bakken and Eagle Ford to provide a slowly declining but significant foundation of tight oil production for the next few decades. The Bakken and Eagle Ford are relatively new plays, with substantial tight oil resources that have only recently been unlocked by directional drilling and hydraulic fracturing.

Tight oil production in all these plays has risen quickly due to rapid increases in drilling rates and sustained high levels of capital input. However, high well- and field-decline rates, coupled with a finite number of drilling locations, suggest that production will drop off sharply when sweet spots are depleted; therefore, the projected long slow production decline of these plays warrants further scrutiny. Section 3 of this report explores the realistic production potential for the Bakken and Eagle Ford in depth.

[10] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

The remainder of tight oil production is expected to come from seven major plays as well as numerous emerging plays, as illustrated in Figure 2-5.

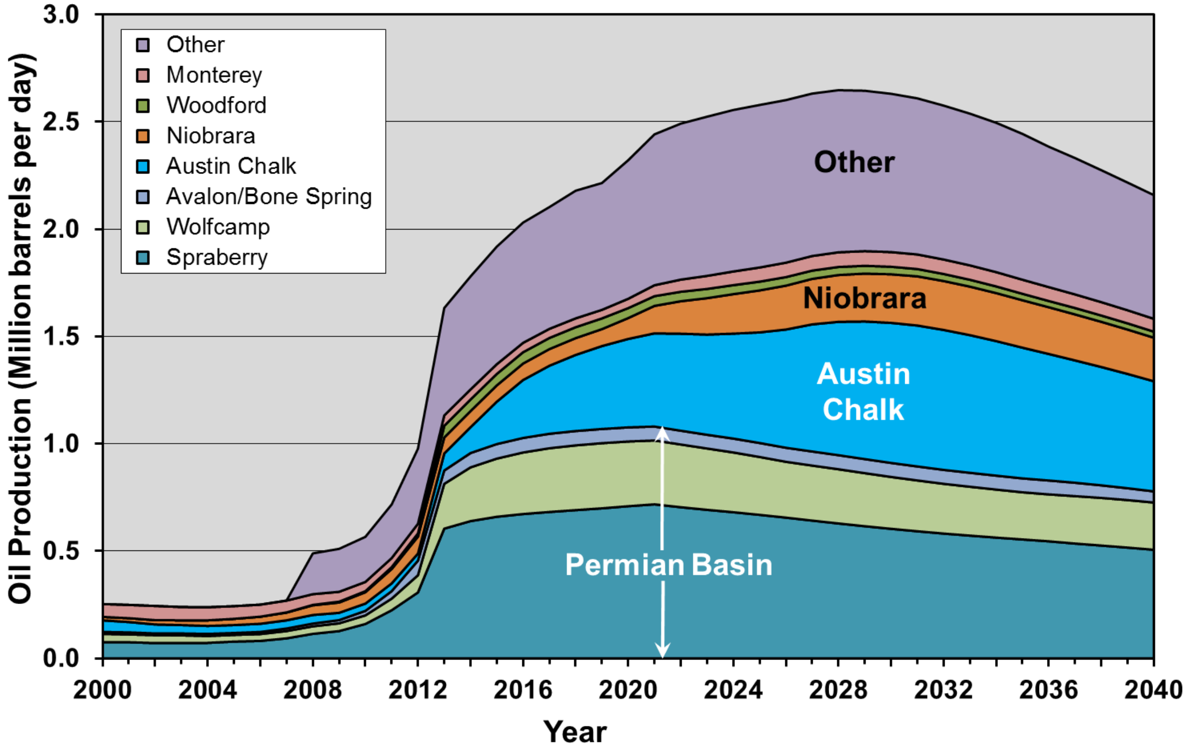


Figure 2-5. EIA reference case projections of tight oil production from plays other than the Bakken and Eagle Ford, through 2040.[11]

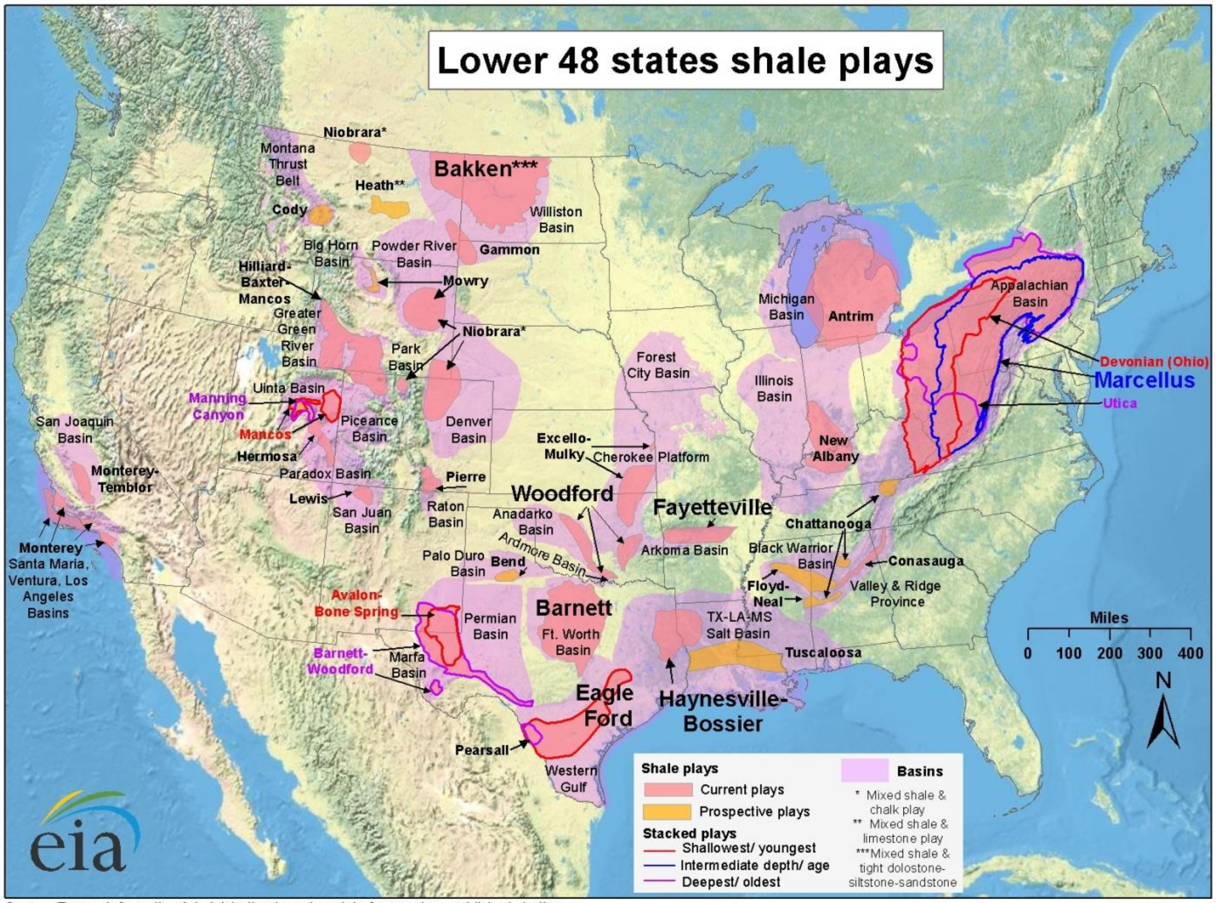
Of the Permian Basin plays, only the top three are labeled here; the remaining are minor plays included in "Other."

Unlike the Bakken and Eagle Ford, most of these plays have been known for a long time; their growing production reflects the successful application of new technology to extract additional resources. They are projected by the EIA to account for two-thirds of tight oil production in 2040; therefore, sustained production projected from these mature plays warrants further scrutiny. Sections 2.4 and 2.5 of this report explore the realistic production potential of these plays in depth.

[11] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

2.2.2 Current U.S. Tight Oil Production

Production of tight oil began in the Bakken Field of Montana and North Dakota in the early 2000s. With the widespread application of horizontal drilling and hydraulic fracturing beginning in 2005, production grew rapidly. The Eagle Ford Field of southern Texas was unknown as recently at 2007, and now is the single largest producer of tight oil in the U.S. The distribution of tight oil and shale gas plays in the lower 48 states is illustrated in Figure 2-6.



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 2-6. Distribution of lower 48 states shale gas and oil plays.[12]

[12] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/.

Current production from U.S. tight oil plays is estimated by the EIA at 3.7 MMbbl/d. Despite the apparent widespread nature of shale plays as shown in Figure 4, 62% of this production comes from just the top two plays: the Bakken and Eagle Ford. A further 25% comes from the five plays of the Permian Basin in Texas and New Mexico. Figure 2-7 illustrates tight oil production by play from 2000 through May, 2014, according to the EIA.

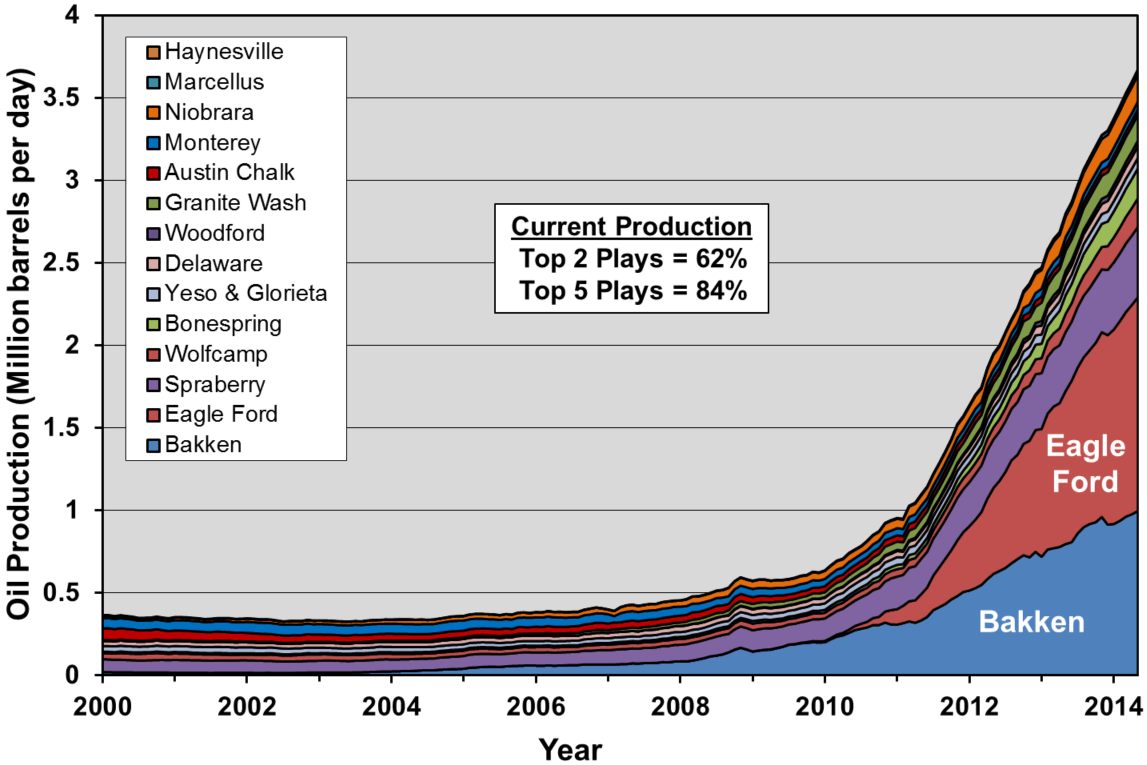


Figure 2-7. U.S. tight oil production by play, 2000 through May 2014.[13]

The Permian Basin, which is made up of several plays (the largest of which are noted), is the third largest projected source of tight oil.

[13] EIA estimates obtained in June 2014 from http://www.eia.gov/naturalgas/weekly, where it appears to have been mistakenly posted; no longer available at this location.

2.3 The Bakken and Eagle Ford Plays

This report investigates the Bakken play and Eagle Ford play in depth because they are the foundation of the U.S. tight oil “shale revolution.” They are the two most productive U.S. tight oil plays, accounting for 62% of current production, and are projected to account for over half of total tight oil production well into the next decade.

Moreover, the Bakken and Eagle Ford are new tight oil plays, having only recently been unlocked by directional drilling and fracking. In comparison, most of the other major U.S. tight oil plays are decades old with tens of thousands of conventional wells. Thus, the Bakken and Eagle Ford are the best representatives of what may be expected from future tight oil discoveries.

2.3.1 Bakken Play

The EIA forecasts recovery of 8.8 billion barrels of oil from the Bakken play by 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Bakken play is where tight oil production got its start—first in the Elm Coulee Field of Montana, then in the western counties of North Dakota. The Bakken Formation is underlain by the Three Forks Formation, which is also productive and is separated from the Bakken by as little as 30 feet. The analysis herein encompasses both the Bakken and Three Forks.

The U.S. Geological Survey (USGS) produced a new assessment of the Bakken and Three Forks in 2013 in which they estimated a mean technically recoverable resource of 7.4 billion barrels.[14] They broke the play into six "assessment units" (AUs) as illustrated in Figure 2-8. The EIA has apparently used this breakdown in its estimates of the play area used to calculate an unproved recoverable resource of 9.2 billion barrels (54% of which are in the Three Forks Formation) in its 2014 reference case; however, it does not provide an updated map showing the areas it has included.[15] In the EIA's analysis, the Bakken play is comprised of five contiguous units totaling 14,594 square miles plus a single underlying Three Forks unit totaling 17,652 square miles (USGS areas for these units, shown in Figure 2-8, are somewhat larger).

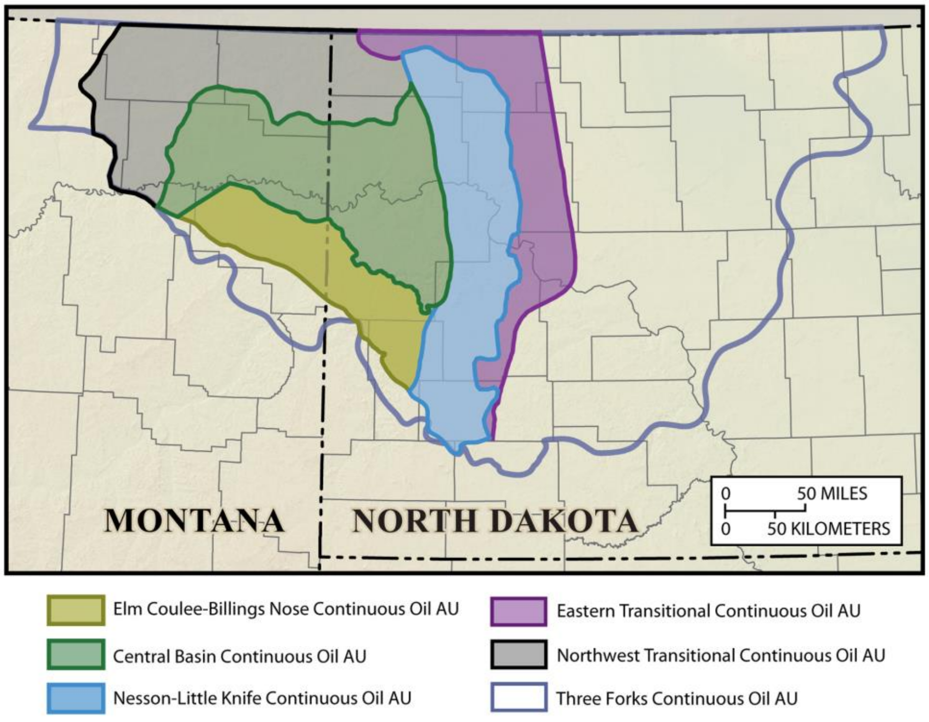


Figure 2-8. USGS demarcation of Bakken and Three Forks tight oil assessment units.[16]
The USGS demarcates five contiguous Bakken units and one underlying, much larger, Three Forks unit.

[14] USGS, *Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota*, 2013, http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.
[15] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf. At publication, the most recent shapefile for the EIA play area was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm.
[16] Map by Post Carbon Institute, using data from USGS, *Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota*, 2013, http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.

Figure 2-9 illustrates the distribution of wells in the Bakken as of early 2014. Over 9,200 wells have been drilled to date, of which 8,534 were producing oil at the time of writing. Although the play covers parts of 15 counties, most drilling is concentrated in McKenzie, Mountrail, Dunn, Williams, and Divide counties in North Dakota and Richland County in Montana. The functional prospective limits of the play are well defined by wells with little or no productivity, and encompass approximately 12,700 square miles; this is a markedly smaller area than the play area demarcated by the EIA.

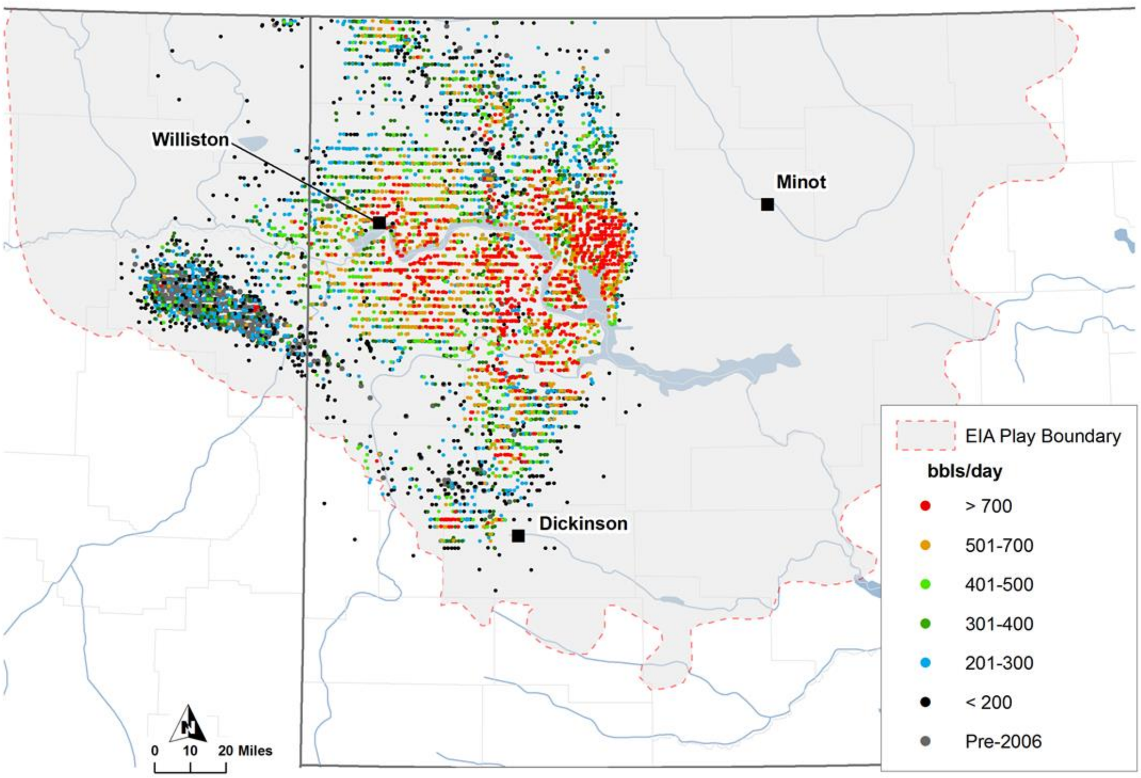


Figure 2-9. Distribution of wells in the Bakken play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP),[17] with EIA play boundary.[18]

The size of the Bakken play as defined by the extent of where productive drilling has actually occurred is approximately 12,700 square miles, in contrast to the much larger area designated as the play by the EIA (2011). Well IPs are categorized approximately by percentile; see Appendix.

The case for such a smaller Bakken play area than what the EIA and USGS claim is further underlain by observing where operators actually have acreage and where drilling is occurring. For example, the leaseholdings of Continental Resources, one of the largest operators in the Bakken, are notably concentrated in the productive area of the play.[19]

[17] Data from Drillinginfo retrieved September 2014.
[18] At publication, the most recent shapefile for the EIA's play area for the Bakken was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata.
[19] Continental Resources, September 2014 investor presentation, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NTU0MDg2fENoaWxkSUQ9MjUwMTQyfFR5cGU9MQ==&t=1.

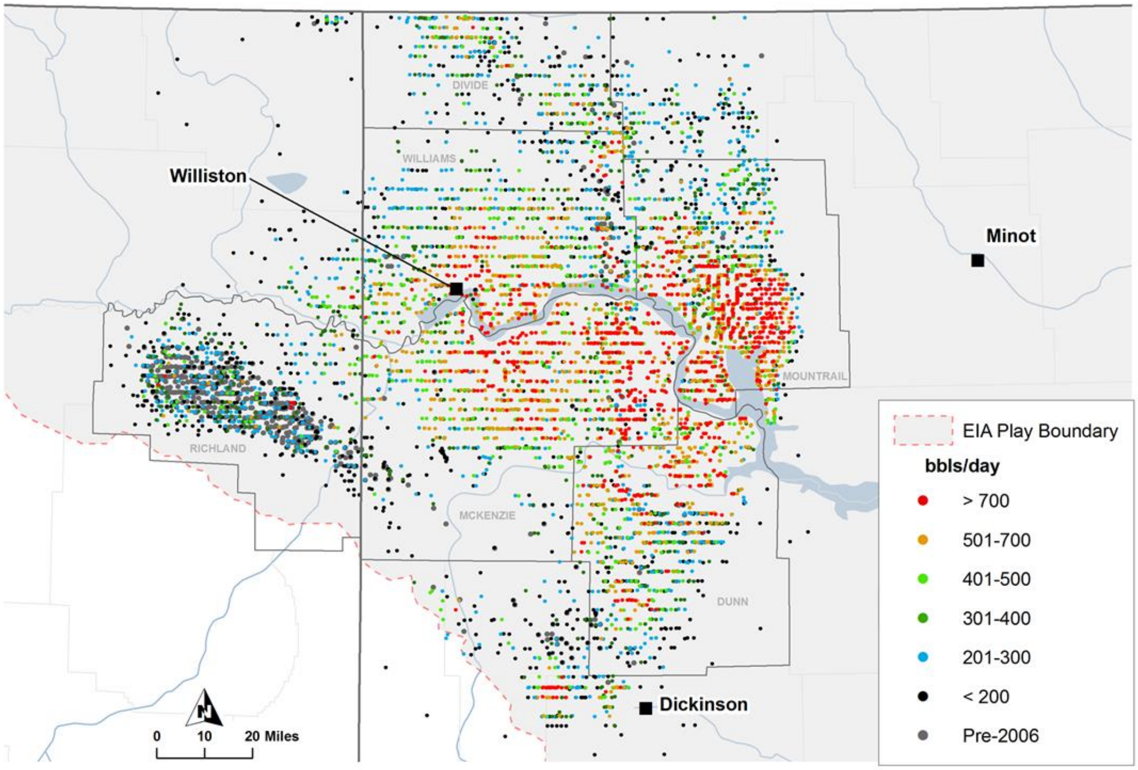


Figure 2-10. Detail of Bakken play showing distribution of wells as of early 2014, and illustrating highest one-month oil production (initial productivity, IP),[20] with EIA play boundary.[21]

The top six producing counties are indicated. Well IPs are categorized approximately by percentile; see Appendix.

[20] Data from Drillinginfo retrieved August 2014.

[21] At publication, the most recent shapefile for the EIA's play area for the Bakken was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata.

Production in the Bakken was nearly one million barrels of oil per day and 1.1 billion cubic feet of gas per day at the time of writing, as illustrated in Figure 2-11.[22] Gas production is expressed in Figure 2-11 as barrels of oil equivalent (6,000 cubic feet of gas equals approximately one barrel of oil on an energy equivalent basis). Ninety-eight percent of this production is from horizontally drilled, hydraulically fractured ("fracked") wells. The rate of drilling has grown from about 500 wells per year in 2009 to about 2,000 wells per year in mid-2012, where it has remained.

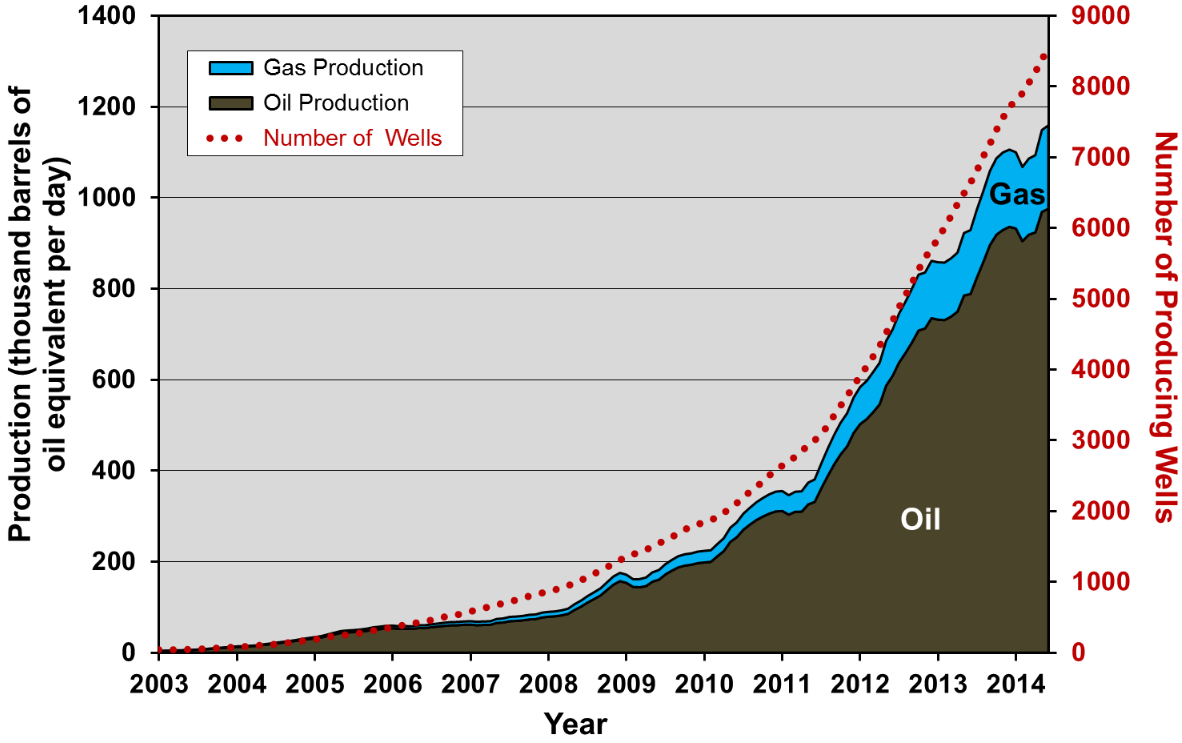


Figure 2-11. Bakken play tight oil and gas production and number of producing wells, 2003 to 2014.[23]

[22] Although the EIA's widely cited Drilling Productivity Report (DPR) states as of September 2014 that Bakken has produced over 1 million barrels per day of oil since February 2014, it must be noted that the DPR's figures for the Bakken seem to overstate production and recent months are based on estimates. See http://www.pphb.com/images/pdfs/musings2014/Musings040114.pdf.
[23] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The amount of oil added to total play production by each new well has been declining since early 2012 as illustrated in Figure 2-12.This is due to the fact that the higher production grows, the more intrinsic decline must be offset by new wells.

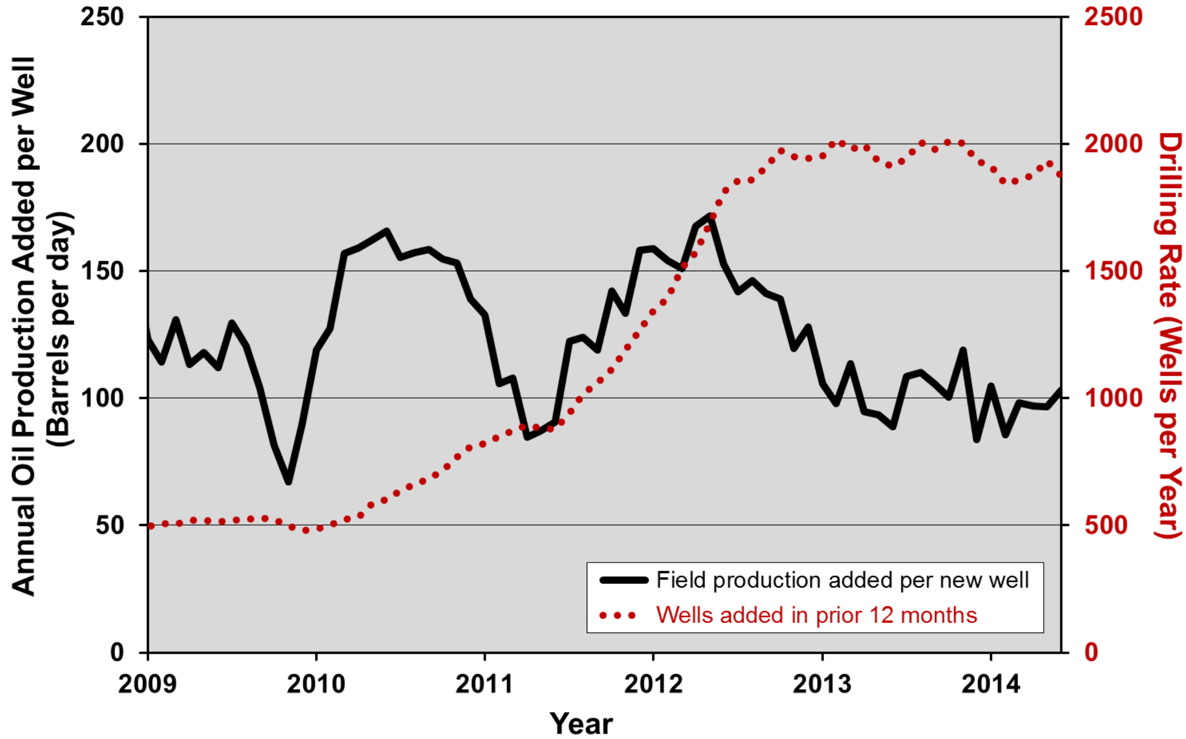


Figure 2-12. Annual oil production added per new well and annual drilling rate in the Bakken play, 2009 through 2014.[24]

[24] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

2.3.1.1 Well Decline

The first key fundamental in determining the life cycle of Bakken production is the *well decline rate*. Bakken wells exhibit high decline rates in common with all shale plays. Figure 2-13 illustrates the average decline profile of Bakken horizontal wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The average decline rate over the first three years of well life is 85%.

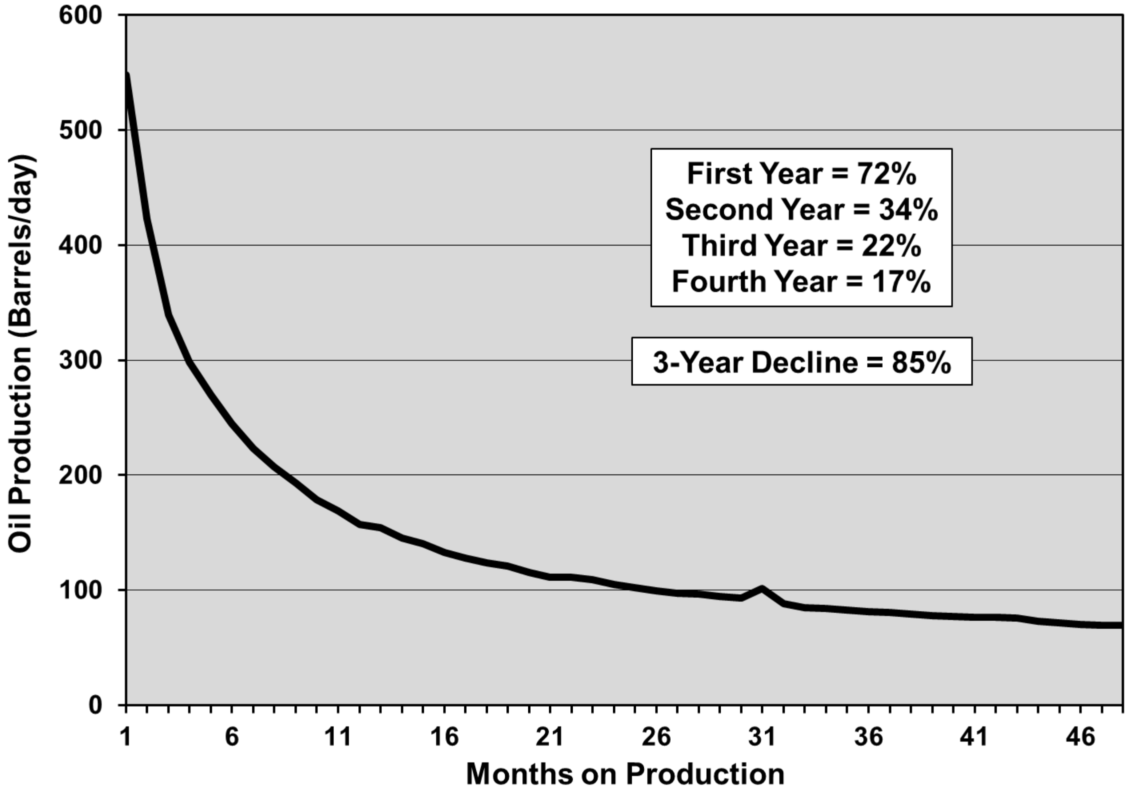


Figure 2-13. Average decline profile for horizontal tight oil wells in the Bakken play.[25]
Decline profile is based on all horizontal tight oil wells drilled since 2009.

[25] Data from Drillinginfo retrieved April 2014.

2.3.1.2 Field Decline

The second key fundamental is the overall *field decline rate*, which is the total amount of production in a given play that would be lost in a year without more drilling. Figure 2-14 illustrates production from the 5,300 wells drilled in the Bakken prior to 2013. The field decline rate of the first year without new drilling is 45%. This is lower than the well decline rate as the field decline is made up of new wells, declining at high rates, and older wells, declining at lesser rates. The field decline has been relatively constant at 45% for the past three years in the Bakken. Assuming new wells will produce in their first year at the first-year rates observed for wells drilled in 2013, 1,470 new wells would need to be drilled each year to offset field decline at current production levels. At an average cost of $8 million per well,[26] this would represent a capital input of about $11.8 billion per year, exclusive of leasing, operating, and other infrastructure costs, just to keep production flat at 2013 levels.

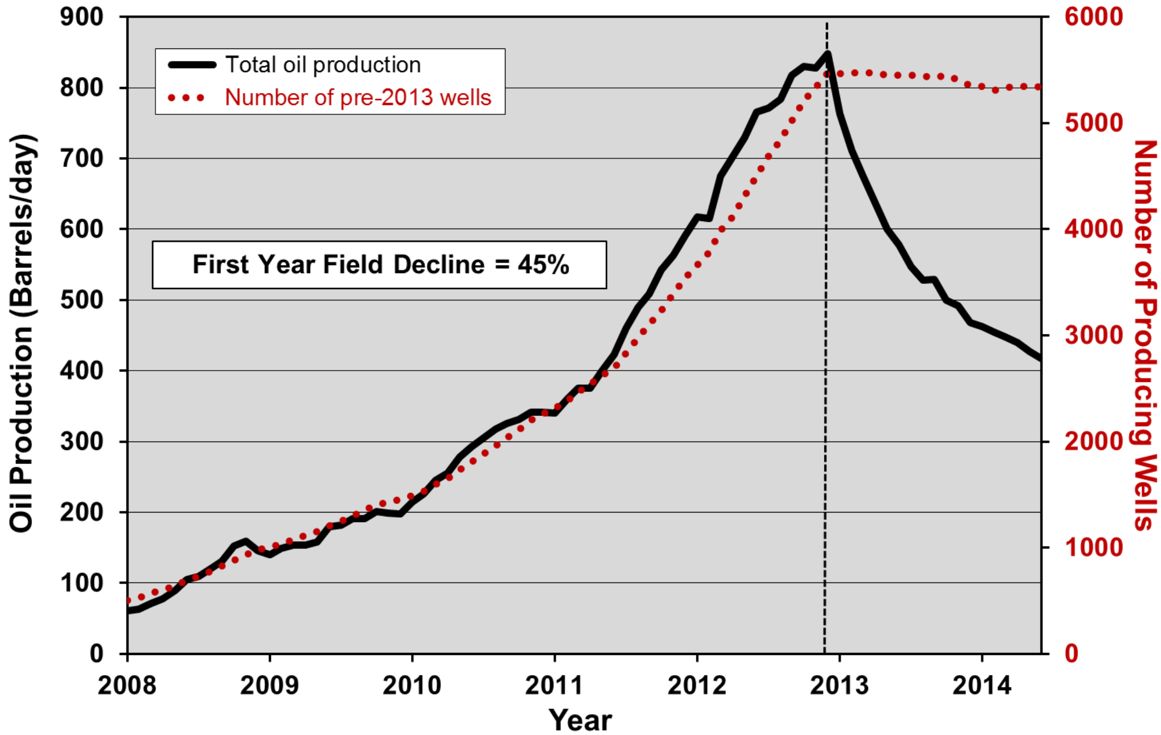


Figure 2-14. Production rate and number of horizontal tight oil wells in the Bakken play prior to 2013.[27]

In order to offset the 45% field decline rate, 1,470 new wells per year producing at 2013 levels would be required.

[26] Ingrid Pan, "Most operators are seeing declining well costs in the Bakken," *Market Realist*, December 12, 2013, http://marketrealist.com/2013/12/operators-seeing-declining-well-costs-bakken.
[27] Data from Drillinginfo retrieved September 2014.

2.3.1.3 Well Quality

The third key fundamental is the trend of *average well quality* over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, which, along with multi-well pad drilling, has reduced well costs. In the Bakken, however, technological improvements appear to be approaching the limits of diminishing returns: improvements in average well quality are flat to slightly increasing at best. The average first-year production rate of Bakken wells is only 7% above its last-highest point, in 2011, as illustrated in Figure 2-15. Moreover, it is likely that this slight rise in average well quality is in part a result of concentrating drilling in the sweet spots, as discussed in the following section, rather than significant technology improvements.

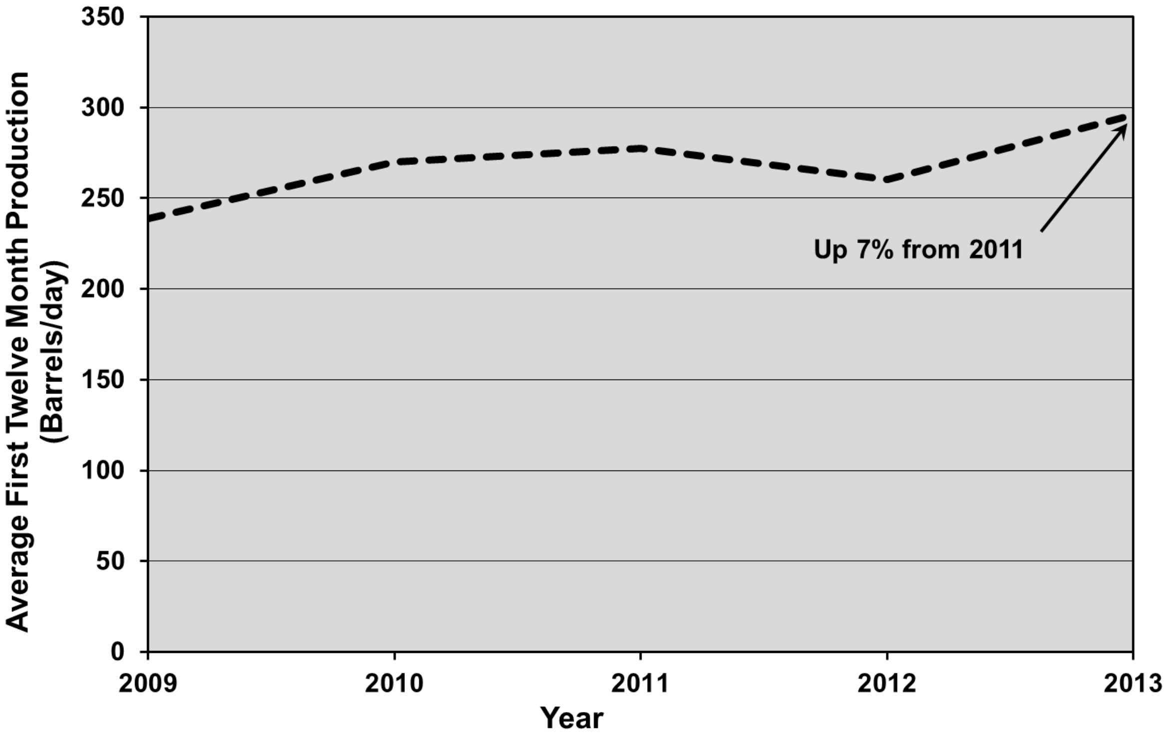


Figure 2-15. Average first-year production rates for Bakken tight oil wells, 2009 to 2013.[28]

The slight improvement over 2011 is likely as much a result of focusing drilling in sweet spots as significant technology improvements.

[28] Data from Drillinginfo retrieved September 2014.

Another measure of well quality is cumulative production and well life. Figure 2-16 illustrates the cumulative production of all wells that were producing in the Bakken as of March 2014. Eighty-two percent of these wells are less than 5 years old, and knowing that production will be down more than 90% after 5 years, their economic lifespan is uncertain. Although it can be seen that there are a few very good wells that recovered more than 600,000 barrels of oil in the first few years, and undoubtedly were great economic successes, the average well has produced just 127,765 barrels over a lifespan averaging 35 months. Only 1% of these wells are more than 10 years old. The lifespan of wells is another key parameter as many operators assume a minimum life of 30 years and longer—this is conjectural at this point given the lack of long-term well-performance data.

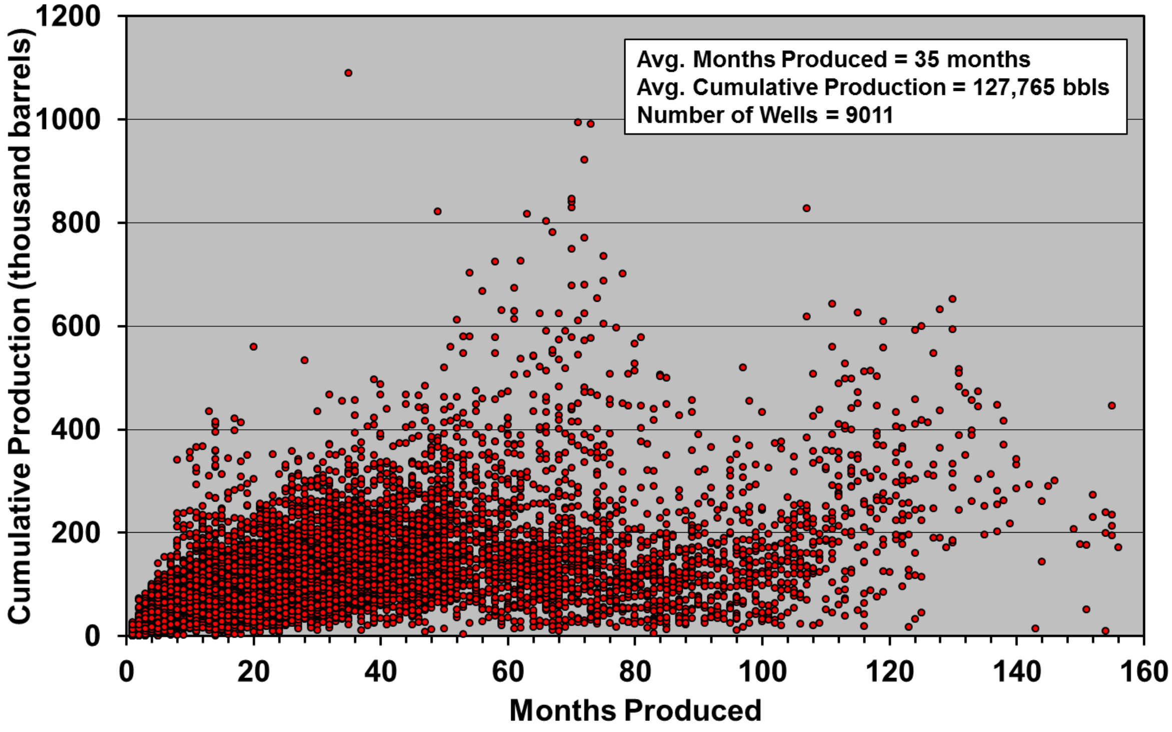


Figure 2-16. Cumulative oil production and length of time produced for Bakken wells that were producing as of March 2014.[29]

Very few wells are greater than ten years old, with a mean age of 35 months and a mean cumulative recovery of 127,765 barrels.

[29] Data from Drillinginfo retrieved September 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells in not necessarily a good indication of how much oil these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP), which is often focused on by operators. Figure 2-17 illustrates the average daily output over the first six months of production (six-month IP) for all wells in the Bakken play. Again, as with cumulative production, there are a few exceptional wells—4% of wells produced more than 600 barrels per day over the first six months—but the average for all wells drilled between 2008 and 2014 is just 262 barrels per day. The trend line on Figure 2-17 shows the average over time, which is declining as of the first half of 2014 as drilling moves into lower-quality areas. Figure 2-9 and Figure 2-10 illustrate the distribution of IPs in map form.

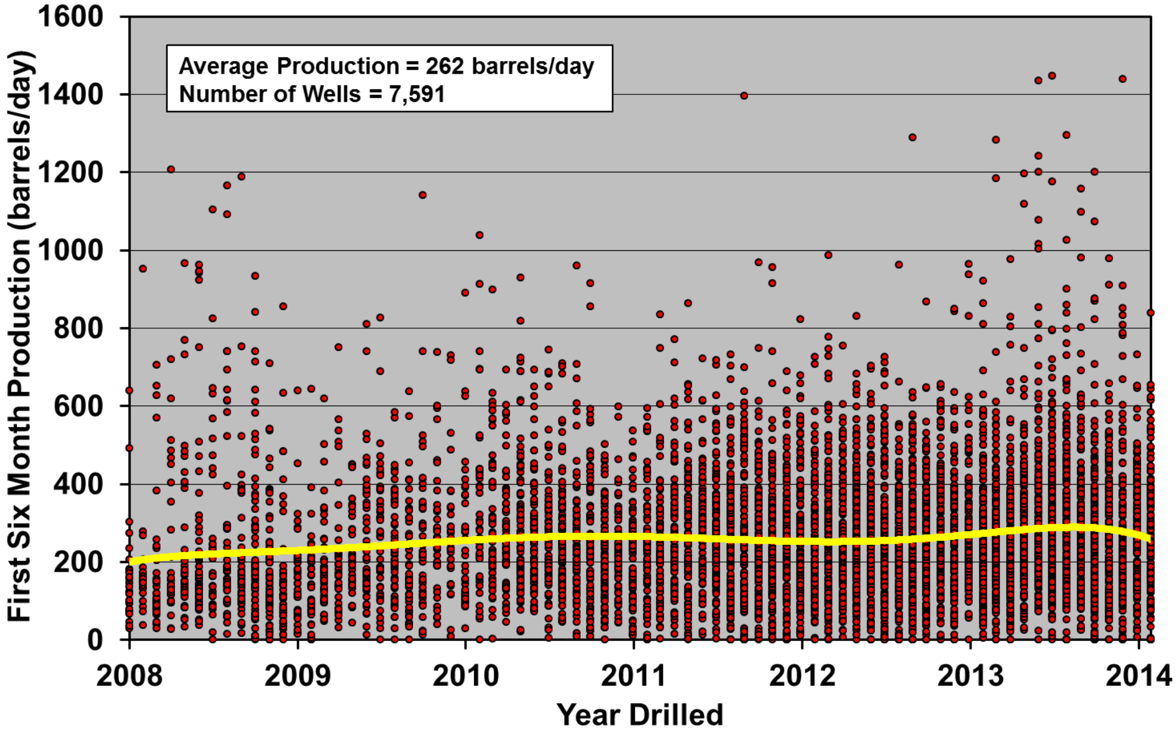


Figure 2-17. Average oil production over the first six months for all wells drilled in the Bakken play, 2008-2014.[30]

Although there are a few exceptional wells, the average well produced 262 barrels per day over this period.

[30] Data from Drillinginfo retrieved September 2014.

Different counties in the Bakken display markedly different well production rate characteristics, which are critical in determining the most likely production profile in the future. Figure 2-18, which illustrates production over time by county, shows that the top two counties produce 55% of the total, the top four produce 87%, and the remaining eleven produce just 13%. Clearly, years of widespread drilling (see Figure 2-19 for number of wells drilled per county) have not resulted in significant production increases outside the top four counties.

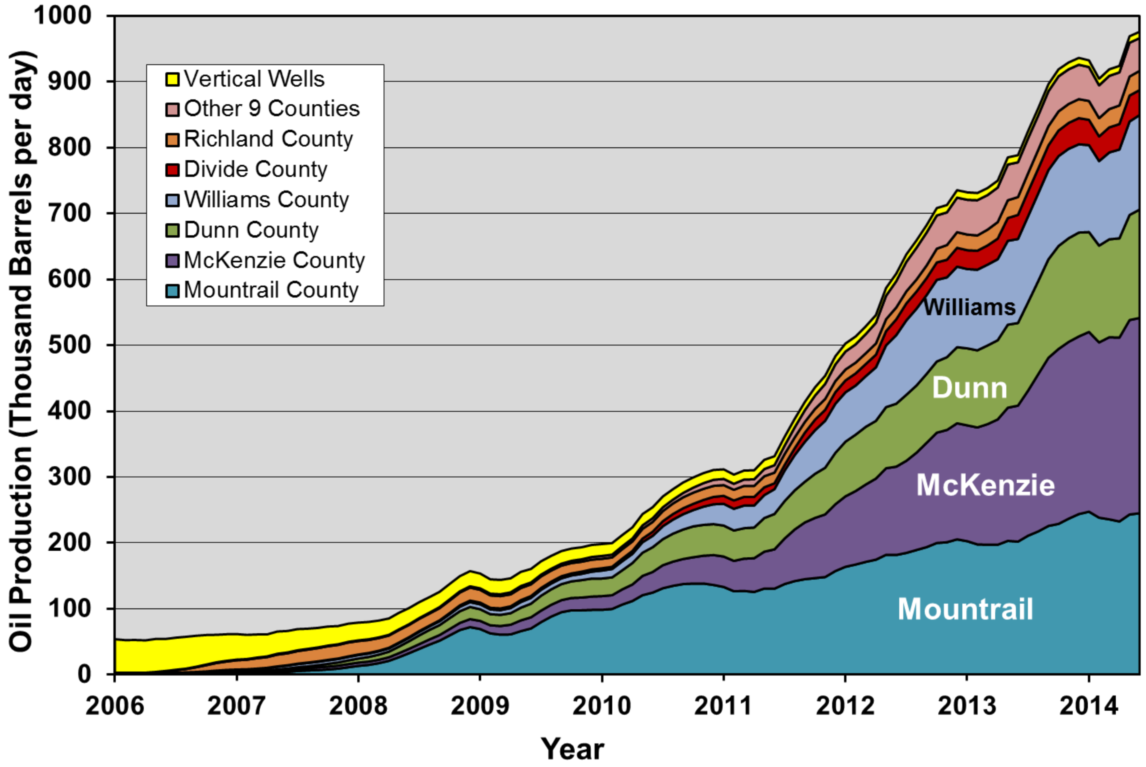


Figure 2-18. Oil production by county in the Bakken play, 2006 through 2014.[31]

The top four counties produced 87% of production in 2014.

[31] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 2-19, the top two counties have produced half of the oil and the top four more than three-quarters. This trend will likely become even more pronounced given that the production rate share from these counties is increasing as noted above.

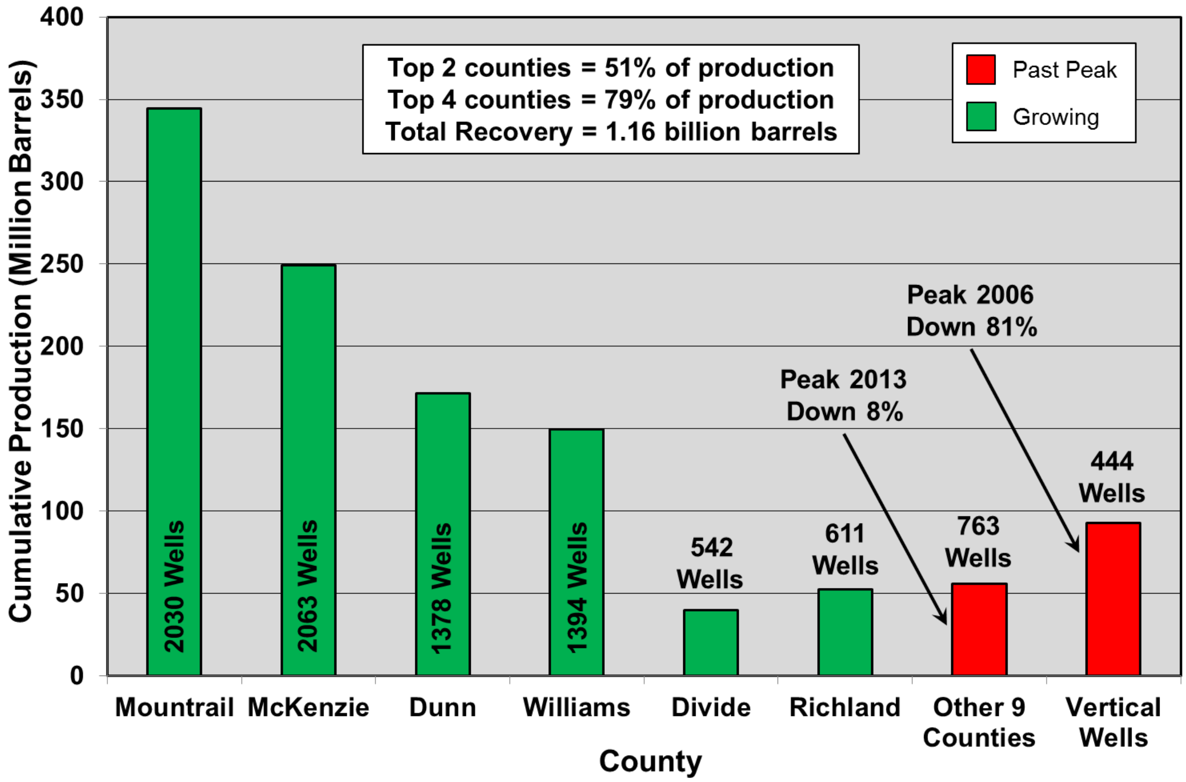


Figure 2-19. Cumulative oil production by county in the Bakken play through 2014.[32]

The top four counties have produced 79% of the 1.16 billion barrels produced to date. Note that production from vertical wells in all counties is grouped at right; the cumulative tallies by county are for horizontal wells only.

[32] Data from Drillinginfo retrieved September 2014.

The Bakken also produces significant amounts of natural gas (see the Bakken section in *Part3: Shale Gas* of this report for a full discussion). As with oil, cumulative production of natural gas is concentrated in the top four counties as illustrated in Figure 2-20. Although natural gas does add value for operators and amounts to 18% of the energy produced from the play, the high discount of natural gas price compared to the price of oil and the lack of gathering infrastructure (particularly in remote regions) have resulted in the flaring of some 30% of production. This has attracted considerable attention, including the enactment of new regulations.[33] The Bakken currently produces about 1.1 billion cubic feet per day and has produced more than one trillion cubic feet since 2006.

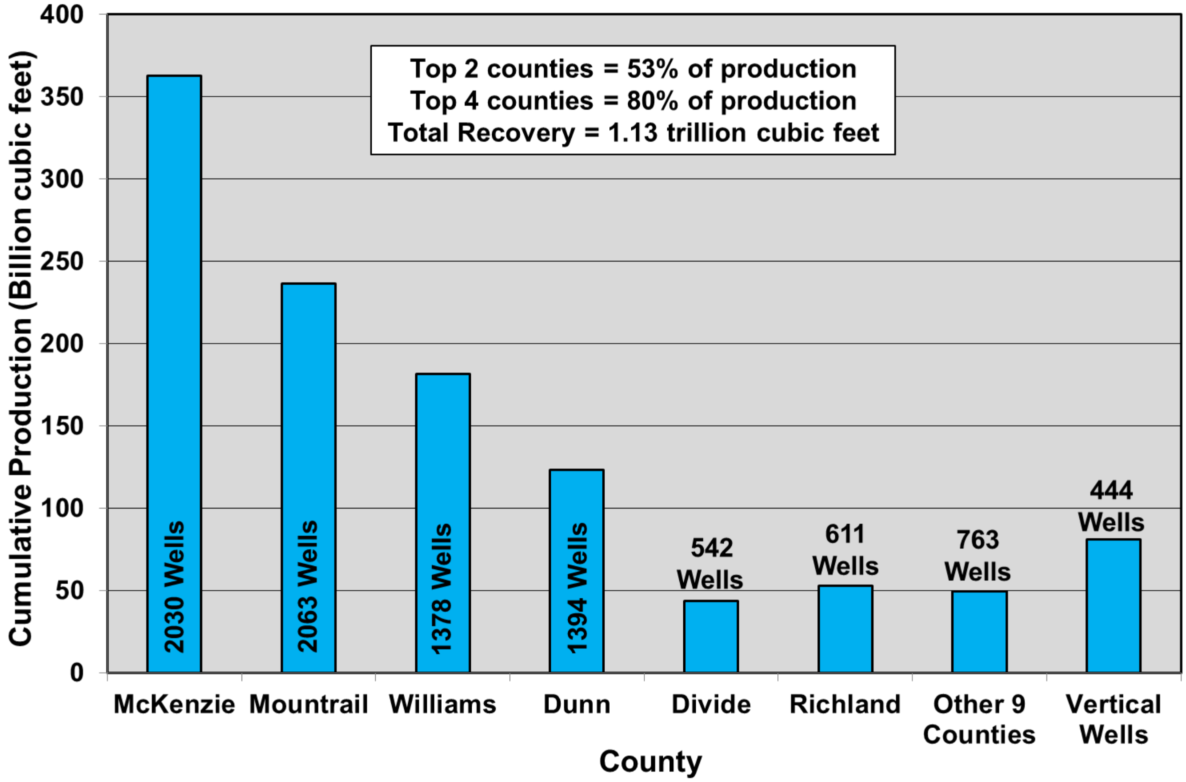


Figure 2-20. Cumulative gas production by county in the Bakken play through 2014.[34]

The top four counties have produced 80% of the 1.13 trillion cubic feet produced to June 2014.

[33] Anna Driver and Ernest Scheyder, "North Dakota flaring crackdown may slow oil field growth," Reuters, June 5, 2014, http://www.reuters.com/article/2014/06/05/bakken-flaring-idUSL1N0OK2AI20140605.

[34] Data from Drillinginfo retrieved September 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost in the order of $8 million or more each, not including leasing costs and other expenses. The areas of highest quality—the “core” or “sweet spots”—have now been well defined. Figure 2-21 illustrates average well decline profiles by county; these can be seen as a measure of well quality. The well decline profiles from the top three counties are all above the Bakken average, hence these counties are attracting the bulk of the drilling and investment.

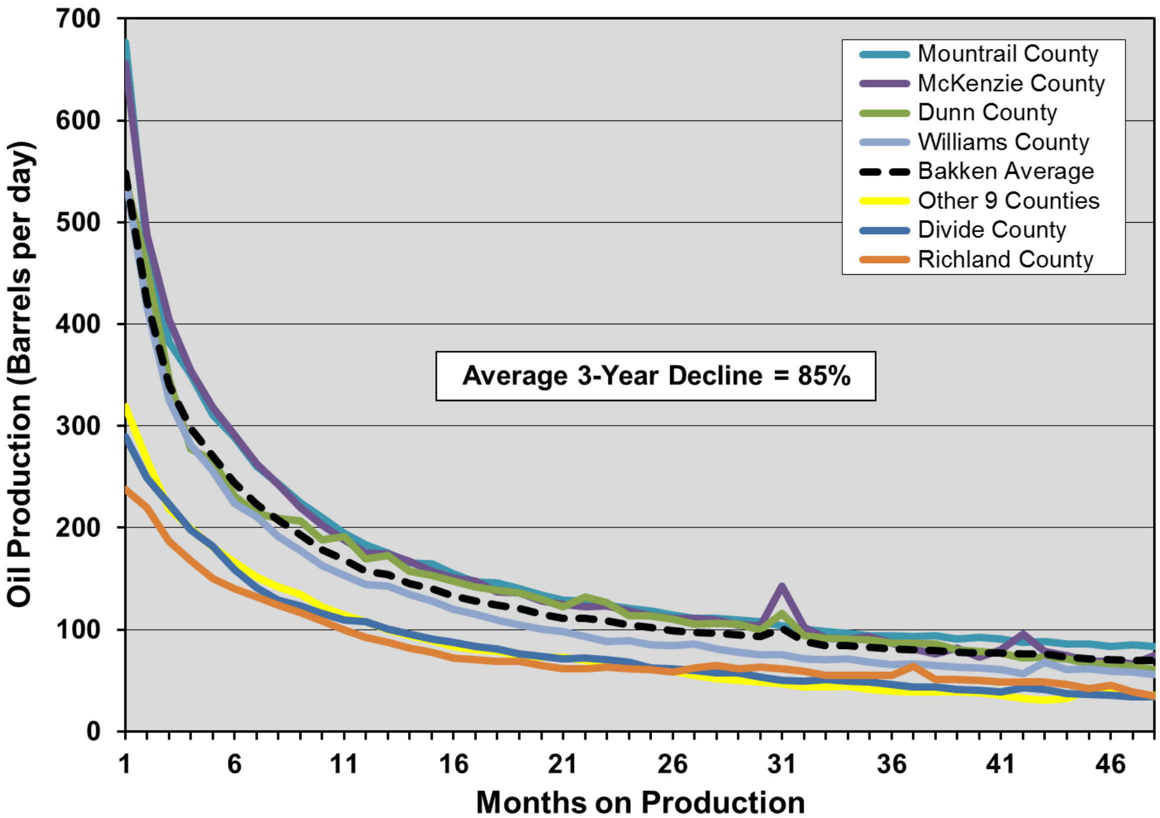


Figure 2-21. Average tight oil well decline profiles by county for the Bakken play.[35]

The top four counties which have produced most of the oil and gas in the Bakken are clearly superior. If natural gas is included, on a “barrels of oil equivalent basis,” average initial production in counties like Mountrail and McKenzie is over 800 barrels per day. Well decline profiles are based on horizontal wells drilled since 2009.

Another measure of well quality is “estimated ultimate recovery” (EUR), the amount of oil a well will recover over its lifetime. To be clear, no one knows what the lifespan of a Bakken well is, given that few of them are more than seven years old. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 2-21, assuming well life spans of 30-50 years (as is typical for conventional oil wells), but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Bakken. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 2-21, which show that wells exhibit steep initial decline rates with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

[35] Data from Drillinginfo retrieved April 2014.

Figure 2-22 illustrates theoretical EURs for horizontal wells by county for the Bakken, for comparative purposes of well quality; these range from 203,000 to 442,000 barrels per well. This compares to EURs of 13,000 to 340,000 barrels per well assumed by the EIA (the EIA weighted mean EUR—based on potential number of wells—is 146,000 barrels).[36] EURs in the top four counties are 50% to more than 100% higher than in the remaining parts of the play. The steep well production declines mean that well payout (if it is achieved) comes in the first few years of production, as between 52% and 62% of an average well's lifetime production occurs in the first four years.

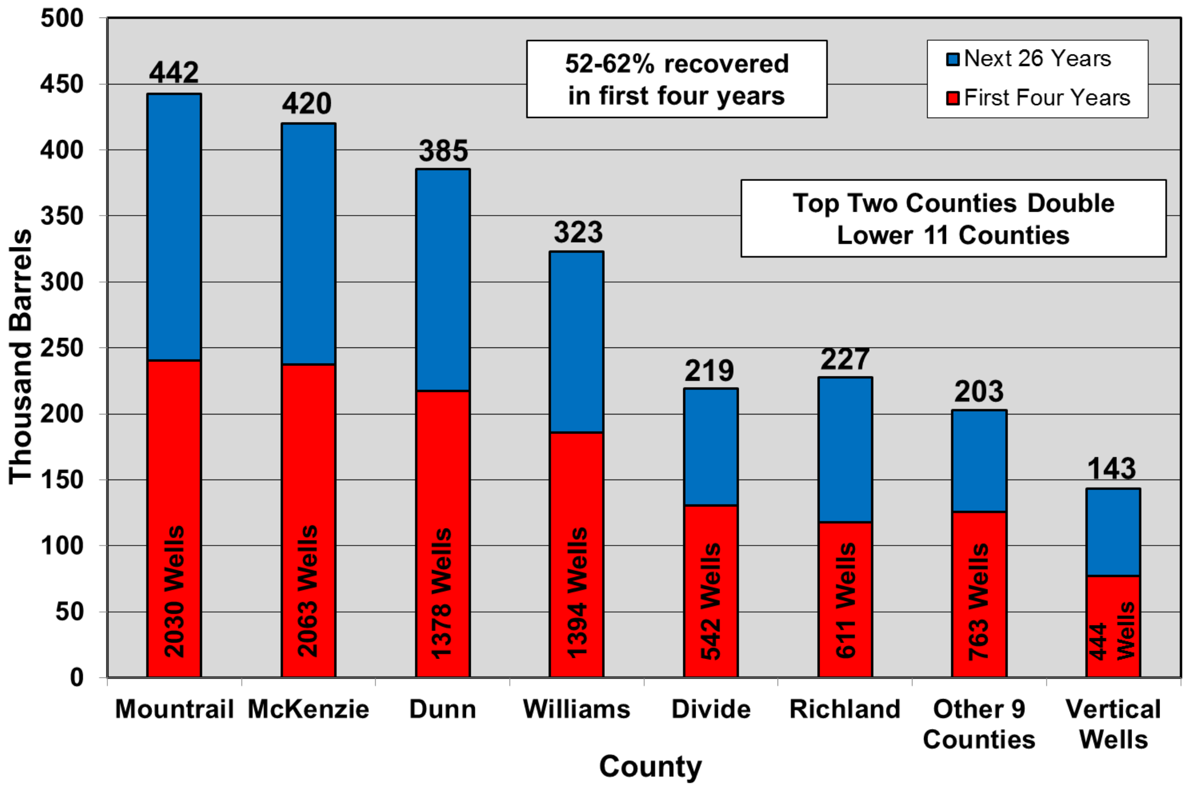


Figure 2-22. Estimated ultimate recovery of oil per well by county for the Bakken play.[37]

EURs are based on average well decline profiles (Figure 2-21) and a terminal decline rate of 13%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years, as are the decline rates at the end of well life. The EURs by county are for horizontal wells only; the EUR for vertical wells is shown at right. The steep decline rates mean that most production occurs early in well life.

[36] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

[37] Data from Drillinginfo retrieved September 2014.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the field's decline rate and the average well's first-year production rate, we can calculate the number of wells that need to be drilled each year in order to offset field decline and maintain production. Given that drilling is currently focused on the highest-quality counties, the average first-year production rate per well will necessarily fall as drilling moves into lower-quality counties over time (i.e., as the best locations are drilled off). As average well quality falls, the number of wells that must be drilled to offset field decline must rise, until the drilling rate can no longer offset decline and the field peaks.

Figure 2-23 illustrates the average first-year oil production rate of wells by county. Notwithstanding modest gains in the top four counties, which are also those that are most densely drilled, future technology improvements are unlikely to postpone for long the inevitable decline in average overall well quality as drilling moves into lower quality counties.

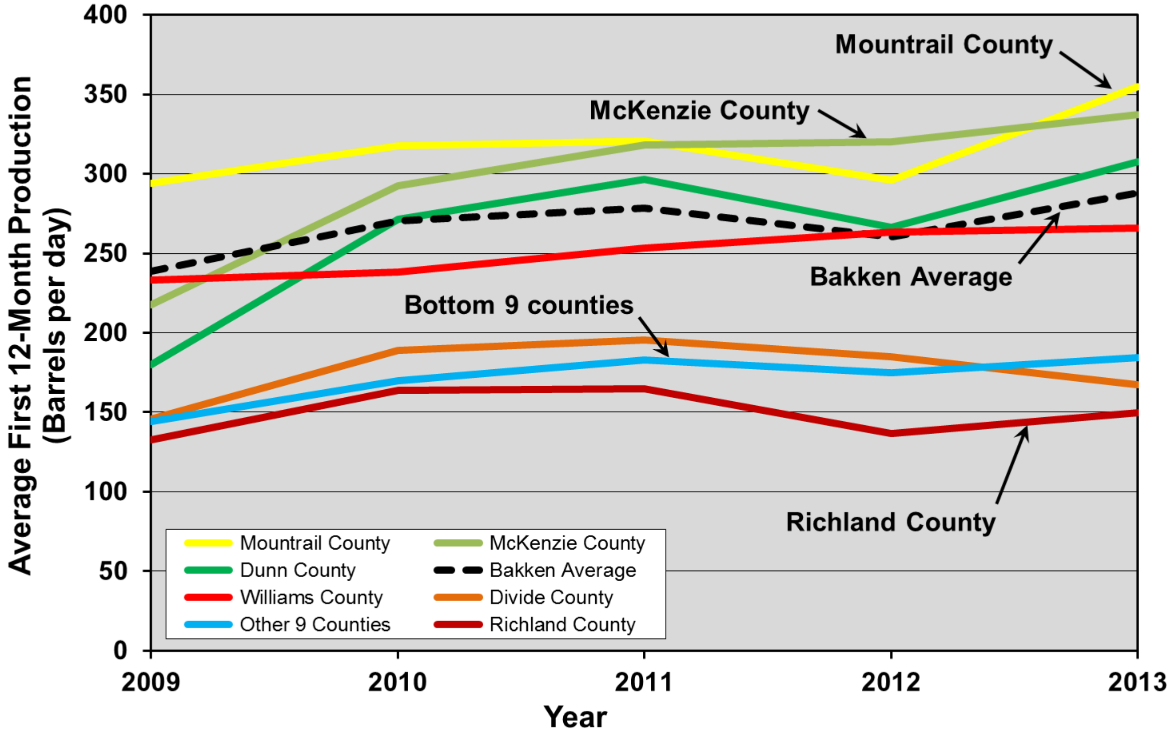


Figure 2-23. Average first-year oil production rates of wells in the Bakken play by county, 2009 to 2013.[38]

Well quality is rising most rapidly in Mountrail County, which is also the county with the current highest well density. First year production rate in the lowest-producing 11 counties, where the bulk of remaining drilling locations are, is flat. The top four counties have roughly double the well quality of the lowest 11.

[38] Data from Drillinginfo retrieved April 2014.

2.3.1.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Bakken, a function of (a) the size of the area worth drilling and (b) the density of drilling that will likely occur. This issue is hotly debated in investor presentations. One of the most optimistic views comes from Continental Resources, one of the first companies to drill in the Bakken, whose CEO claims 100,000 wells may ultimately be drilled.[39] The North Dakota Industrial Commission is bullish, but less so, at 40,000 wells[40] in addition to the 9,225 already drilled. In contrast, the EIA estimates 73,697 wells, 29,186 of which are in the Bakken with the remainder in the Three Forks (obtained from the product of well density and play area in the EIA assumptions[41]).

Determining the likely density at which operators will drill wells requires consideration of both the geology of the play and the mechanics of hydraulic fracturing. Typical wells in the Bakken have horizontal laterals of 10,000 feet in length with 25 or more frack stages. The EIA suggests that the Bakken may be drilled at a density of 2 wells per square mile[42] which would space horizontal laterals 1,320 feet from each other. One operator, Enerplus, suggests (based on a drilling pilot in one of the best areas) that 3.5 wells can be drilled per square mile, including both the Bakken and Three Forks.[43] Continental is testing downspacing of horizontal laterals to just 660 feet apart on four layers of the Bakken and Three Forks, which, if successful, could be up to a staggering 16 wells per square mile.[44] There is no confirmation if this actually worked over a period of time long enough to assess the degree of interference between wells, which would only become apparent after 6-12 or more months of production history.

Wells spaced less than 2,000 feet apart in the Bakken may undergo interference, meaning that wells cannibalize each other's oil over time, as noted by Thuot, based on an empirical analysis of Bakken data.[45] This means that although oil can be produced more quickly by spacing wells closer together than 2,000 feet, the ultimate amount of oil produced per well will be reduced, and the total amount of oil recovered per unit area will not be substantially increased. Thuot concludes:

1. *Well interference in the Bakken appears to occur for hydraulically fractured horizontal wellbores spaced closer than roughly 2,000 feet.*

2. *The magnitude of well interference on production appears to increase over time.*

3. *The full impact of well interference in the analysis above is likely somewhat masked since operators become more proficient in drilling and completion techniques over time. As we saw, secondary wells over-perform when spaced wider than 2,000 feet.*

---

[39] Christopher Helman, "Harold Hamm: The Billionaire Oilman Fueling America's Recovery," *Forbes*, April 16, 2014, http://www.forbes.com/sites/christopherhelman/2014/04/16/harold-hamm-billionaire-fueling-americas-recovery.
[40] North Dakota Industrial Commission, *Development of the Bakken Resource*, June 11, 2014, https://www.dmr.nd.gov/oilgas/presentations/ActivityUpdate2014-06-11NCSLBismarck.pdf.
[41] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[42] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[43] Enerplus, "A Deeper Look into the Williston Basin" investor presentation, June 18, 2014, http://www.enerplus.com/files/pdf/investor-relations/Williston%20Basin%20Deck_June%2018_FINAL%202.pdf.
[44] Continental Resources, July 2014 Investor presentation, retrieved August 2014 from http://investors.clr.com/phoenix.zhtml?c=197380&p=irol-presentations.
[45] Kevin Thuot, "There Will Be Blood: Well Spacing & The Bakken Shale Oil Milkshake," Drillinginfo, November 26, 2013, http://info.drillinginfo.com/well-spacing-bakken-shale-oil.

This implies that fractures propagated from a wellbore drain in the order of 1,000 feet from the well. Given that 2 wells per square mile places 10,000 foot laterals 1,320 feet apart, a 2,000-foot spacing would require considerably lower well densities.

Given that the four layers ("benches") of the Three Forks lie between 80 and 250 feet below the middle Bakken target zone, it is likely that wells drilled in the middle Bakken are also draining oil from at least some of the underlying Three Forks benches, ultimately limiting the number of wells needed to effectively recover the oil. Therefore, there are practical limits to well downspacing..

Determining the area actually conducive to drilling is comparatively straightforward. After years of exploration and thousands of wells drilled, operators have delineated the limits of the play and focused their efforts on those areas with proven potential; thus by identifying the farthest-lying wells with little to no production as the likely edge of the play, and estimating the size of the area within that edge which is clearly attracting industry interest, the functional area of the Bakken play can be calculated. By this method, the area likely to be conducive to drilling is approximately 12,700 square miles (see Figure 2-9).

Based on the above parameters, and given the fact that much of the area covered by the Bakken is of much lower quality than the top four counties, an estimate of two wells per square mile may be reasonable for the whole area, with an estimate of three wells per square mile being on the optimistic upside. This translates to approximately 25,400 wells if drilled at a density of two wells per square mile, and 38,100 wells locations if drilled at a density of three wells per square mile. Allowing three wells per square mile on average over the whole region would provide for greater density in the best quality parts of the play and lower density in the outlying lower quality areas.

Of course, these estimates assume that the entire area designated as the Bakken play is available for drilling—failing to account for parks, towns, rivers, reservoirs, and other areas not conducive to drilling. A slightly more conservative but possibly more realistic calculation would include a "risk" that 20% of the play's remaining area will be undrillable. After accounting for wells already drilled, this risk would reduce the total number of potential wells to approximately 21,400 and 31,500 for the two- and three-well per section cases, respectively. Either way, the Bakken play could experience somewhere between three and four times the number of wells drilled to date.

2.3.1.5 Rate of Drilling

The fifth key fundamental is the *rate of drilling*. As noted earlier, the Bakken play has a field decline of 45% per year, meaning that 45% of production has to be replaced with new wells each year to keep production flat. As the amount of oil produced from an average well in its first year of production is known from the data, the number of wells needed to offset field production decline each year at a given production level can be easily calculated. For the Bakken, at current production levels, some 1,470 wells must be drilled each year just to keep production flat. Since drilling rates in the Bakken are now at about 2,000 wells per year, production will keep growing as long as these rates are sustained. However, the higher production grows, the more wells are needed to offset the 45% field decline. And as drilling moves into lower quality parts of the play, even more wells will be needed, for as illustrated above (Figure 2-23), well quality in 11 of the 15 counties is at least 40% lower than in the best four.

2.3.1.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Bakken play were developed to illustrate the effects of changing the rate of drilling and the number of drilling locations. These production projections intentionally ignore questions of economics (e.g., the amount of capital required and whether oil prices would support drilling in less productive areas) or politics (e.g., community opposition, new government regulation) in order to analyze what is technically possible.

The projections are given in three cases, differentiated by the number of drilling locations:

1. A "Low Well Density Case" of 100% of the play area being drillable, at 2 wells per square mile. (The EIA assumes that 2 wells can be drilled per square mile in the Bakken and 2.5 wells per square mile can be drilled in the underlying Three Forks.)

2. An "Optimistic Case" of 100% of the play area being drillable at 3 wells per square mile.

3. A "Realistic Case" of 80% of the remaining play area being drillable (i.e., the remaining play area is "risked" at 80% to account for undrillable areas like parks, towns, rivers, etc.), at 3 wells per section.

Each case includes three scenarios, differentiated by the rate of drilling:

1. MOST LIKELY RATE scenario: Drilling continues at the current rate of 2,000 wells per year and then declines to 1,000 wells per year as drilling moves into the lower quality counties.

2. EXPANDED RATE scenario: Drilling increases to 2,500 wells per year and then declines to 1,500 wells per year as drilling moves into the lower quality counties.

3. FASTEST RATE scenario: Drilling is increased 50% over the current rate to 3,000 wells per year, and held constant until locations run out.

The critical parameters used for determining production rates in these scenarios are given in Table 2-1.

Parameters	Counties							Total
	Divide	Dunn	McKenzie	Mountrail	Richland	Williams	Other 9	
Production Jan 2014 (Kbbl/d)	38	165	296	245	29	143	50	966
% of Field Production	4	17	31	25	3	15	5	100
Cumulative Oil (million bbls)	40	172	249	344	52	150	56	1063
Cumulative Gas (Bcf)	44	123	363	237	53	182	49	1050
Number of Wells	542	1378	2063	2030	611	1394	763	8781
Number of Horizontal Producing Wells	524	1282	1875	1896	565	1318	693	8153
Average EUR per well (Kbbls)	219	385	420	443	227	323	203	378
Field Decline (%)	51	38	49	40	30	50	54	45
3-Year Well Decline (%)	85	84	88	86	73	88	88	85
Average First Year Production in 2013 (bbl/d)	169	308	344	376	148	271	180	296
New Wells Needed to Offset Field Decline	115	202	418	258	60	266	150	1468
Area in square miles	1259	2010	2742	1824	2084	2071	18000	29990
% Prospective	60	60	75	65	55	90	25	39
Net square miles	755	1206	2057	1186	1146	1864	4500	12714
Well Density per square mile	0.72	1.14	1.00	1.71	0.53	0.75	0.17	0.75
Additional locations to 2/sq. Mile	969	1034	2050	341	1681	2334	8237	16646
Additional locations to 3/sq. Mile	1724	2240	4107	1527	2828	4198	12737	29360
Population	2071	3536	6360	7673	9667	22398	N/A	N/A
Total Wells 2/sq. Mile	1511	2412	4113	2371	2292	3728	9000	25427
Total Wells 3/sq. Mile	2266	3618	6170	3557	3439	5592	13500	38141
Total Wells 2/sq. Mile Risked at 80%	1317	2205	3703	2303	1956	3261	7353	22098
Total Wells 3/sq. Mile Risked at 80%	1921	3170	5348	3251	2873	4752	10953	32269

Table 2-1. Parameters for projecting Bakken tight oil production, by county

Area in square miles under “Other” is estimated.

Low Well Density Case

In the "Low Well Density Case" (Figure 2-24), assuming 100% of the area is drillable, approximately 17,700 wells remain to be drilled on top of the more than 8,500 wells currently producing, for a total of 25,500 wells (including wells no longer producing).

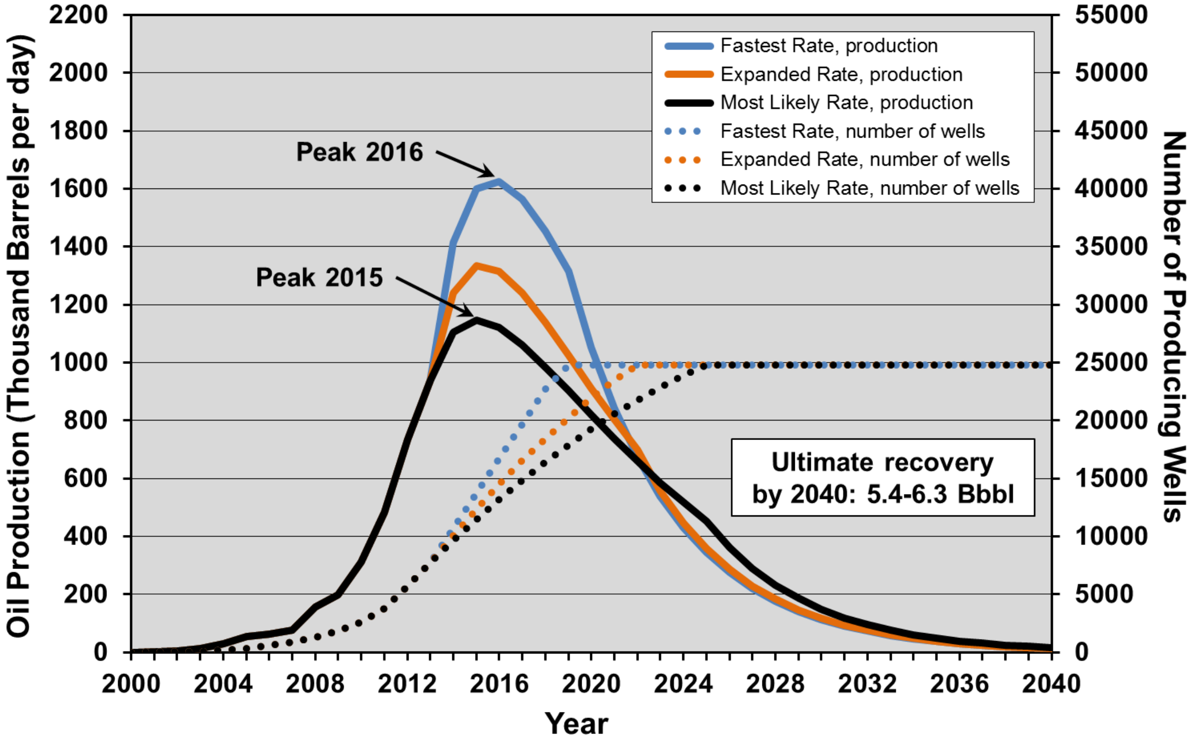


Figure 2-24. Three drilling rate scenarios of Bakken tight oil production, in the "Low Well Density Case" (100% of play area is drillable at two wells per square mile).[46]

"Most Likely Rate" scenario: drilling continues at 2,000 wells/year, declining to 1,000 wells/year;
"Expanded Rate" scenario: drilling increases to 2,500 wells/year, declining to 1,500 wells/year;
"Fastest Rate" scenario: drilling increases to 3,000 wells/year, holding constant.

The drilling rate scenarios in this case have the following results:

1. MOST LIKELY RATE scenario: Peak production occurs in 2015 at 1.15 MMbbl/d. Drilling continues until 2025, and total oil recovery by 2040 is 5.4 billion barrels.

2. EXPANDED RATE scenario: Peak production occurs in 2015 at 1.33 MMbbl/d. Drilling continues until 2022, and total oil recovery by 2040 is 5.7 billion barrels. Production would be lower after 2023 than in the "Most Likely Rate" case as faster drilling would recover the oil sooner.

3. FASTEST RATE scenario: Peak production occurs in 2016 at 1.63 MMbbl/d. Drilling continues until 2019, and total oil recovery by 2040 is 6.3 billion barrels. As in the "Expanded Rate" scenario, production would be lower after 2023 than in the "Most Likely Rate" case.

---

[46] Data from Drillinginfo retrieved September 2014.

Optimistic Case

If technological advances allow for a denser drilling footprint of three wells per section, ultimate recovery increases somewhat—but the timing of production peaks remain virtually the same (pushed back by only a year). This case would see the drilling of 29,400 wells on top of the more than 8,500 currently producing wells for a total of 38,100 wells (including wells no longer producing). Figure 2-25 illustrates this "Optimistic Case."

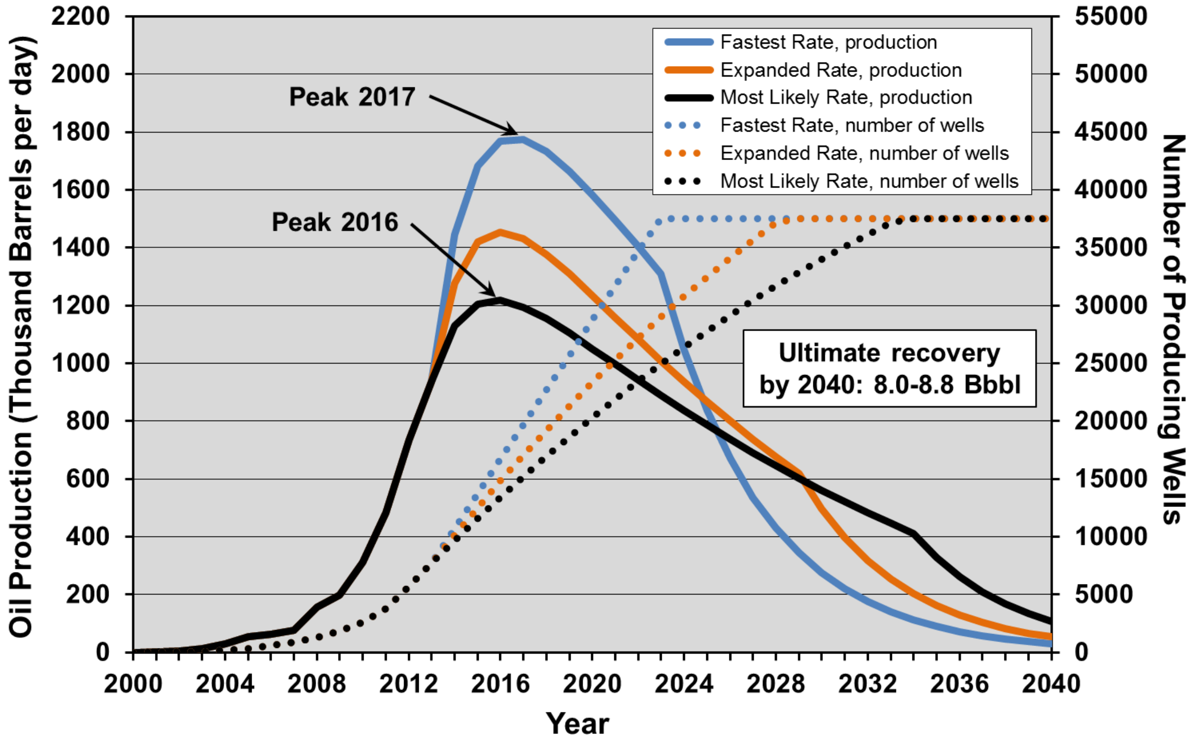


Figure 2-25. Three drilling rate scenarios of Bakken tight oil production, in the "Optimistic Case" (100% of play area is drillable at three wells per square mile).[47]

"Most Likely Rate" scenario: drilling continues at 2,000 wells/year, declining to 1,000 wells/year;
"Expanded Rate" scenario: drilling increases to 2,500 wells/year, declining to 1,500 wells/year;
"Fastest Rate" scenario: drilling increases to 3,000 wells/year, holding constant.

The drilling rate scenarios in this case have the following results:

1. MOST LIKELY RATE scenario: Peak production occurs in 2016 at 1.22 MMbbl/d. Drilling continues until 2034, and total oil recovery by 2040 is 8.0 billion barrels.

2. EXPANDED RATE scenario: Peak production occurs in 2016 at 1.45 MMbbl/d. Drilling continues until 2029, and total oil recovery by 2040 is 8.3 billion barrels.

3. FASTEST RATE scenario: Peak production occurs in 2017 at 1.77 MMbbl/d. Drilling continues until 2023, and total oil recovery by 2040 is 8.8 billion barrels. In this scenario, production would be considerably lower after 2026 than in the "Most Likely Rate" scenario.

[47] Data from Drillinginfo retrieved September 2014.

Realistic Case

A more realistic case (Figure 2-26) is that 80% of the remaining play area will be drillable at three wells per square mile (i.e., the case includes a "risk" that 20% of the play remaining area will be undrillable). This allows for surface features that preclude drilling, such as towns, rivers, reservoirs, parks and other surface features which may limit access for drilling. This scenario would see the drilling of 23,500 wells on top of the more than 8,500 currently producing wells for a total of 32,300 wells (including wells no longer producing).

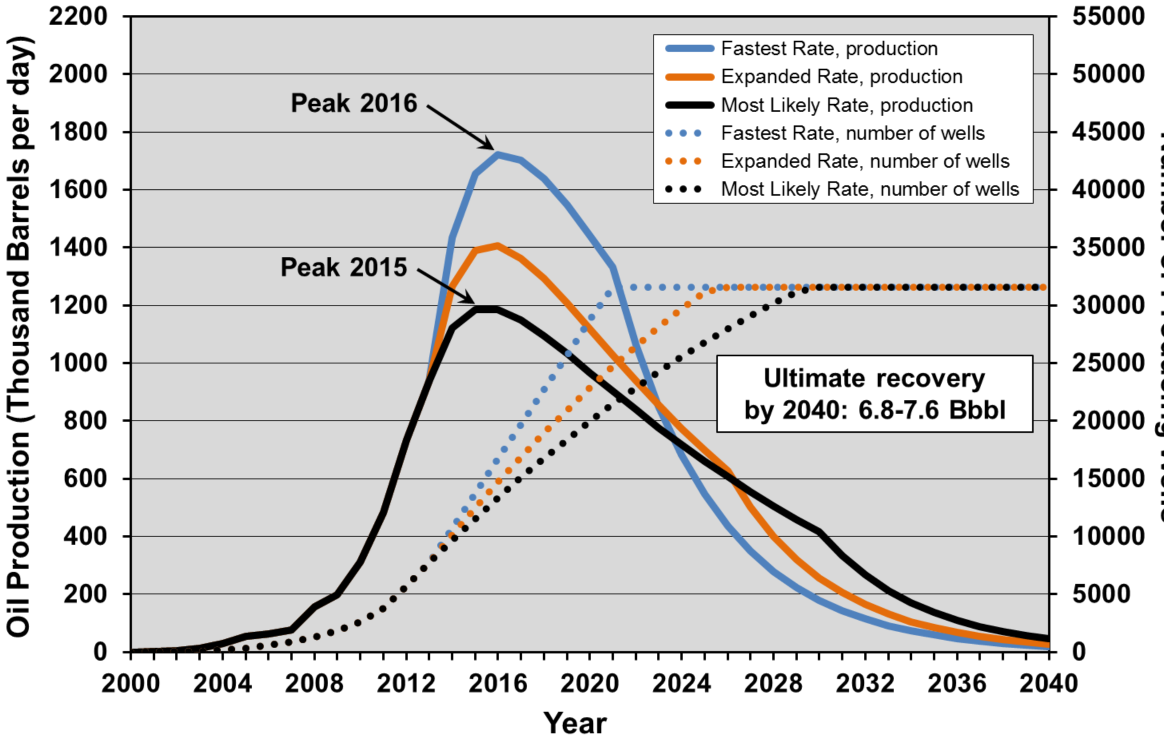


Figure 2-26. Three drilling rate scenarios of Bakken tight oil production, in the "Realistic Case" (80% of the remaining play area is drillable at three wells per square mile).[48]

"Most Likely Rate" scenario: drilling continues at 2,000 wells/year, declining to 1,000 wells/year;
"Expanded Rate" scenario: drilling increases to 2,500 wells/year, declining to 1,500 wells/year;
"Fastest Rate" scenario: drilling increases to 3,000 wells/year, holding constant.

The drilling rate scenarios in this case have the following results:

1. MOST LIKELY RATE scenario: Peak production occurs in 2015 at 1.19 MMbbl/d. Drilling continues until 2030, and total oil recovery by 2040 is 6.8 billion barrels.

2. EXPANDED RATE scenario: Peak production occurs in 2016 at 1.41 MMbbl/d. Drilling continues until 2026, and total oil recovery by 2040 is 7.1 billion barrels.

3. FASTEST RATE scenario: Peak production occurs in 2016 at 1.72 MMbbl/d. Drilling continues until 2021, and total oil recovery by 2040 is 7.6 billion barrels. In this scenario, production would be considerably lower after 2024 than in the "Most Likely Rate" scenario.

[48] Data from Drillinginfo retrieved September 2014.

2.3.1.7 Comparison to EIA Forecast

Figure 2-27 compares the EIA's reference case projection for Bakken tight oil production to the "Most Likely Rate" scenario of the "Realistic" case presented above.

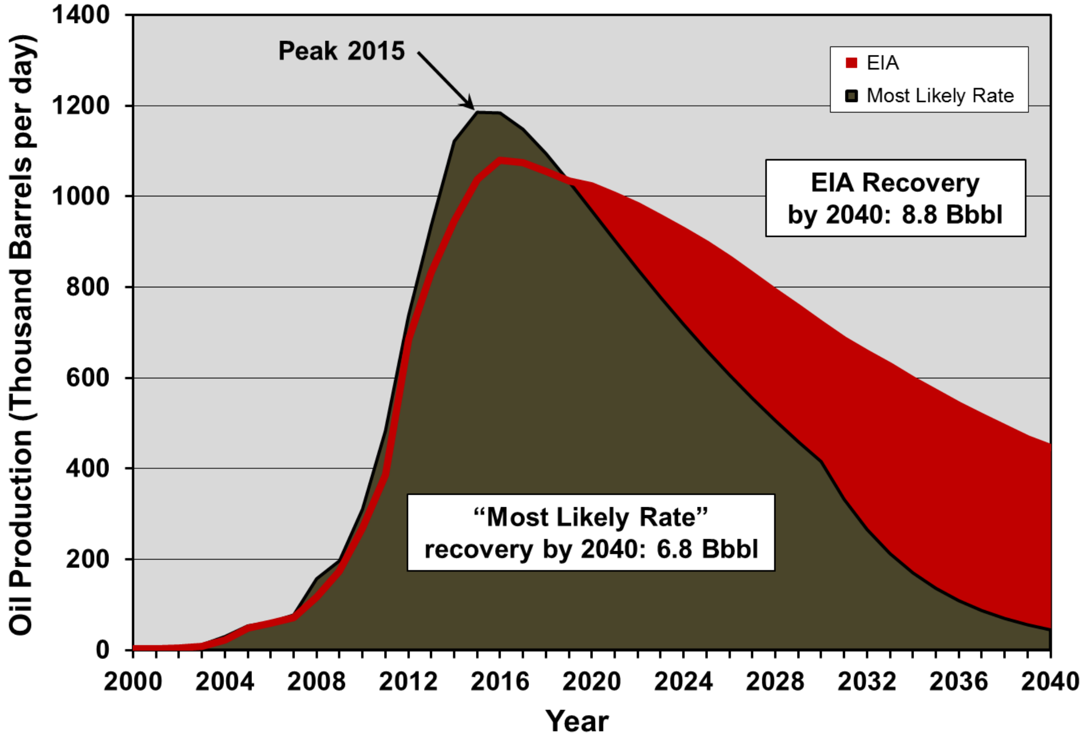


Figure 2-27. "Most Likely Rate" scenario ("Realistic" case) of Bakken tight oil production compared to the EIA reference case, 2000 to 2040.[49]

In this "Most Likely Rate" scenario, drilling continues at 2,000 wells/year, declining to 1,000 wells/year.

This comparison reveals:

- The EIA's forecast of the timing of peak production (2016) in the Bakken is similar to the projection of this report.
- The EIA's forecast of the production rate at peak (1.08 million bpd) is lower than the projection of this report (1.19 million bpd), but only slightly.
- The EIA projects a higher tail of production after peak, with estimated ultimate recovery (EUR) of 8.8 billion barrels by 2040 (7.9 billion for 2014-2040) as opposed this report's projection of 6.8 billion barrels by 2040 (5.7 billion for 2014-2040).

In short, the EIA is forecasting 2.2 billion additional barrels of future Bakken production than this report finds substantiated.

[49] EIA, *Annual Energy Outlook 2014*.

2.3.1.8 Bakken Play Analysis Summary

Several conclusions can be made from the foregoing analysis of the Bakken play:

1. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. The observed 45% per year field decline rate requires the drilling of 1,470 wells per year just to maintain current production levels.

2. The production profile is most dependent on drilling rate and to a lesser extent the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Drilling rate is determined by capital input, which currently is about $16 billion per year to drill 2,000 wells, not including leasing and other ancillary costs.

3. Peak production is highly likely to occur in the 2015 to 2017 timeframe and will occur at between 1.15 and 1.77 MMbbl/d. The most likely peak is between 1.15 and 1.22 MMbbl/d in the 2015 to 2016 timeframe.

4. Increased drilling rates will raise the level of peak production and move it forward a few months but do not appreciably increase cumulative oil recovery through 2040. Increased drilling rates effectively recover the oil sooner, making the supply situation worse later.

5. The projected recovery of 6.8 billion barrels by 2040 in the “Most Likely Rate” scenario (2,000 wells/year declining to 1,000 wells/year) of the “Realistic” case (80% of play drillable, at 3 wells per square mile), agrees fairly well with the mean estimate of latest USGS assessment of the Bakken (including the Three Forks) of 7.4 billion barrels.[50]

6. These projections are optimistic in that they assume the capital will be available for the drilling “treadmill” that must be maintained (roughly $188 billion is needed to drill more than 23,500 wells, exclusive of leasing and ancillary costs). This is not a sure thing as drilling in the poorer-quality parts of the play will require much higher oil prices to be economic. Failure to maintain drilling rates will result in a steeper drop-off in production.

7. Nearly four times the current number of wells will be required to recover 6.8 billion barrels by 2040 in the “Realistic” case.

8. Projections that the Bakken will continue to grow and then maintain a plateau followed by a gentle decline for the foreseeable future[51] are unlikely to be realized.

[50] USGS, *Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota*, 2013, http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.
[51] North Dakota Industrial Commission, *Development of the Bakken Resource*, June 11, 2014, https://www.dmr.nd.gov/oilgas/presentations/ActivityUpdate2014-06-11NCSLBismarck.pdf.

2.3.2 Eagle Ford Play

The EIA forecasts recovery of 10.8 billion barrels of oil from the Eagle Ford play by 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Eagle Ford play of southern Texas is now the largest tight oil play in the U.S; it was unknown prior to 2007. In the EIA's analysis, the Eagle Ford play totals 11,165 square miles.[52] This report considers a surface area for the Eagle Ford defined by where productive drilling has actually occurred; after years of exploration, Eagle Ford producers have presumably focused their efforts on those areas with proven potential. By identifying the farthest-lying wells with little to no production as the likely edge of the play, and estimating the size of the area within that edge that is clearly attracting industry interest, the functional prospective area of the Eagle Ford play is calculated at approximately 7,200 square miles. Forecasts of production outside this area cannot substantiated by currently available drilling information. Figure 2-28 illustrates the distribution of tight oil wells as of mid- 2014 as well as the significantly larger EIA play boundary. More than 10,500 wells have been drilled to date, of which 10,088 were producing oil at the time of writing.

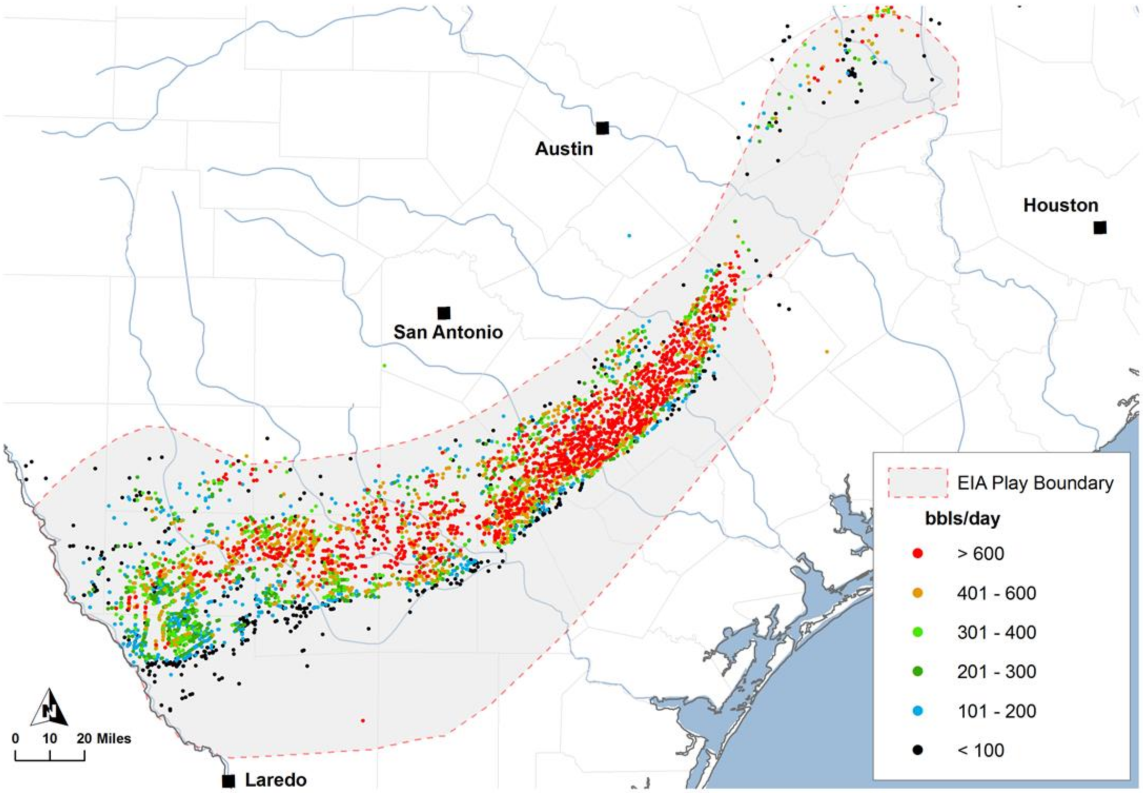


Figure 2-28. Distribution of wells in the Eagle Ford as of mid-2014 illustrating highest one-month oil production (initial productivity, IP),[53] with EIA play boundary.[54]

The size of the Eagle Ford play as defined by the extent of where productive drilling has actually occurred is approximately 7,200 square miles, in contrast to the much larger area designated as the play by the EIA. Well IPs are categorized approximately by percentile; see Appendix.

[52] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf .
[53] Data from Drillinginfo retrieved August 2014.
[54] At publication, the most recent shapefile for the EIA's play area for the Eagle Ford was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata.

The play covers parts of 28 counties although most drilling is concentrated in six counties which account for 81% of production.

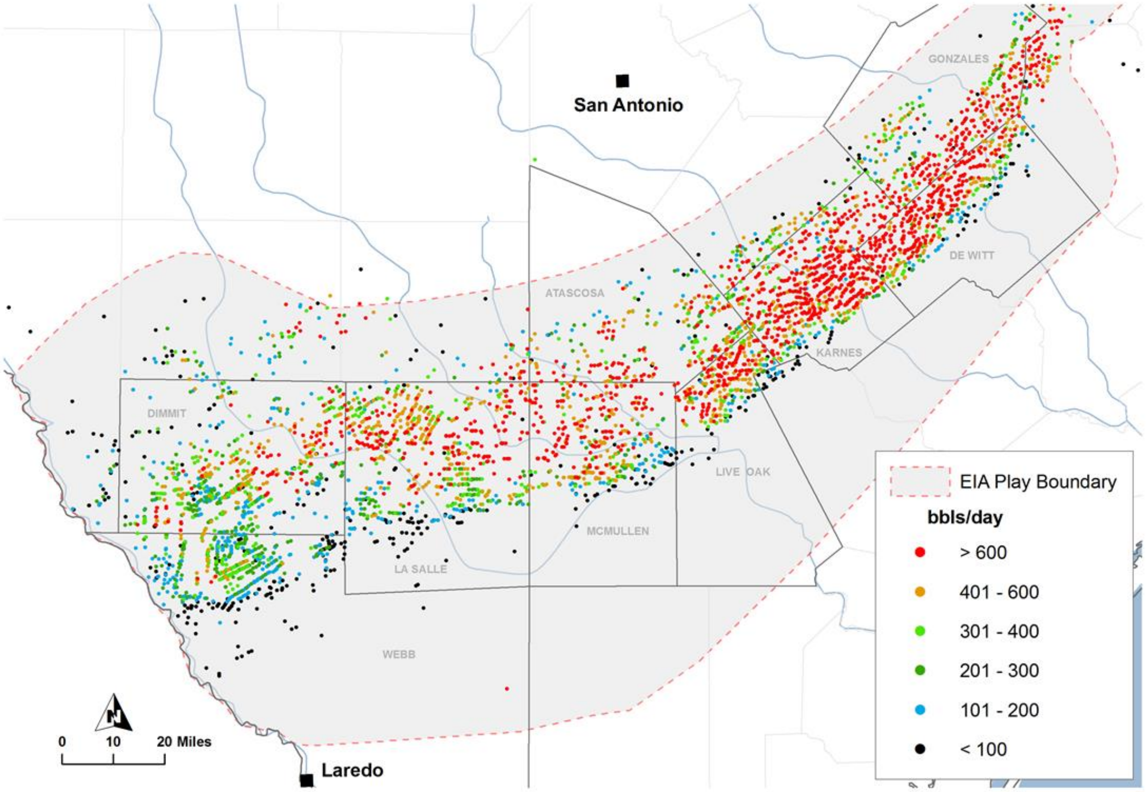


Figure 2-29. Detail of Eagle Ford play showing distribution of wells as of mid-2014 illustrating highest one-month oil production (initial productivity, IP),[55] with EIA play boundary.[56]

The top six producing counties are indicated. Well IPs are categorized approximately by percentile; see Appendix.

---

[55] Data from Drillinginfo retrieved August 2014.

[56] At publication, the most recent shapefile for the EIA's play area for the Eagle Ford was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata.

The Eagle Ford is both a prolific oil producer and a natural gas producer. It has oil, wet gas and dry gas windows, with oil being produced up dip (i.e., in the shallower part of the formation) along the northwestern portion of the field and gas in the down dip (i.e., in the deeper part of the formation) southeastern portion. Figure 2-30 illustrates the distribution of wells classified as "oil" and "gas" in the main part of the field stretching northeast from the Mexican border.

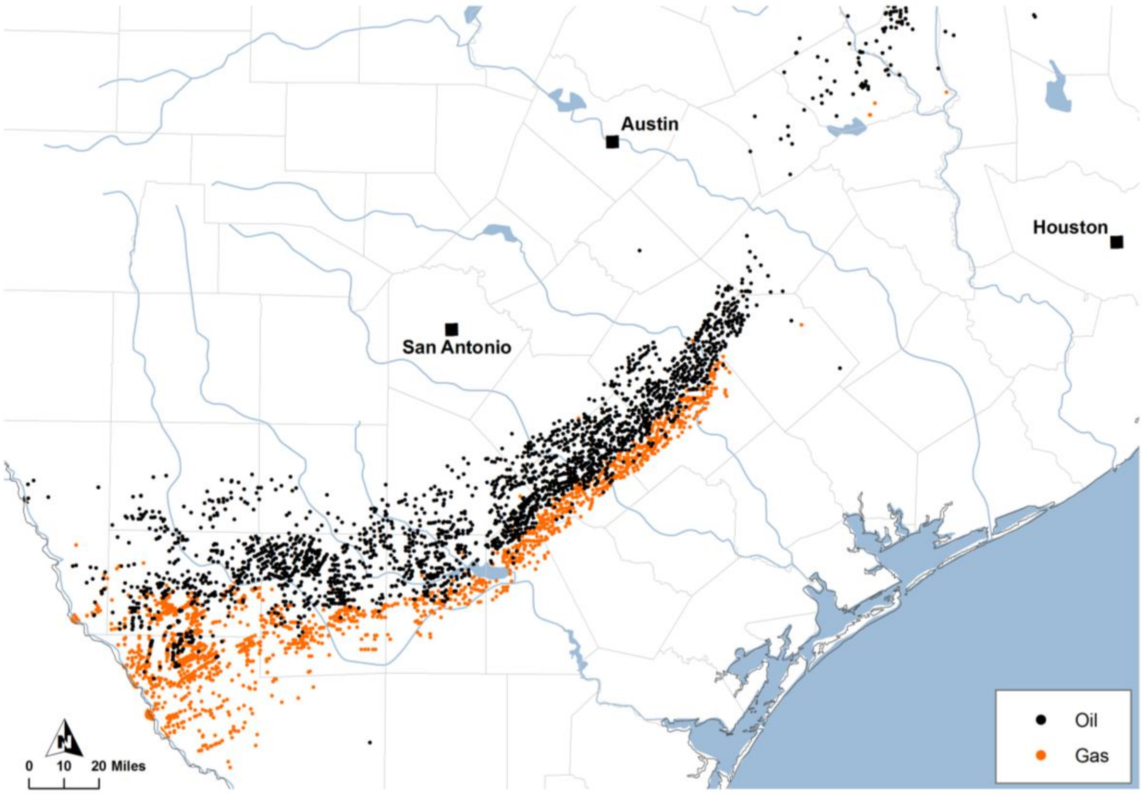


Figure 2-30. Distribution of oil and gas wells in the main portion of the Eagle Ford play as of early 2014.[57]

The Mexican border is on the left. Orange wells are classified as "gas" and black wells are classified as "oil".

[57] Data from Drillinginfo retrieved August 2014.

Production in the Eagle Ford was nearly 1.3 million barrels of oil and 4.9 billion cubic feet of gas per day at the time of writing, as illustrated in Figure 23. Gas production is expressed in Figure 2-31 as barrels of oil equivalent (6,000 cubic feet of gas equals approximately one barrel of oil on an energy equivalent basis). Ninety-eight percent of this production is from horizontal fracked wells. The rate of drilling has grown from about 500 wells per year in early 2011 to about 3,500 wells per year in 2014.

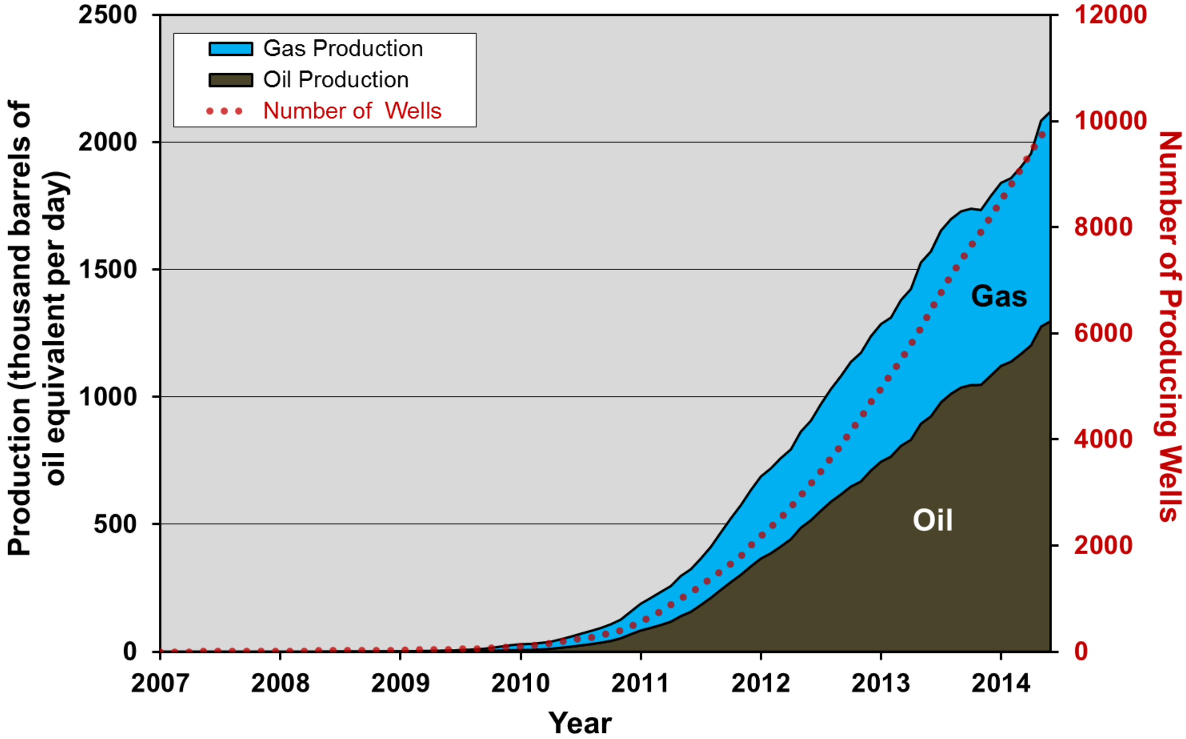


Figure 2-31. Eagle Ford play tight oil and gas production and number of producing wells, 2007 to 2014.[58]

Gas production is expressed as "barrels of oil equivalent" (6,000 cubic feet of gas is approximately equivalent to one barrel of oil on an energy basis).

[58] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The amount of oil added to total play production by each new well has been declining since mid-2011 as illustrated in Figure 2-32.

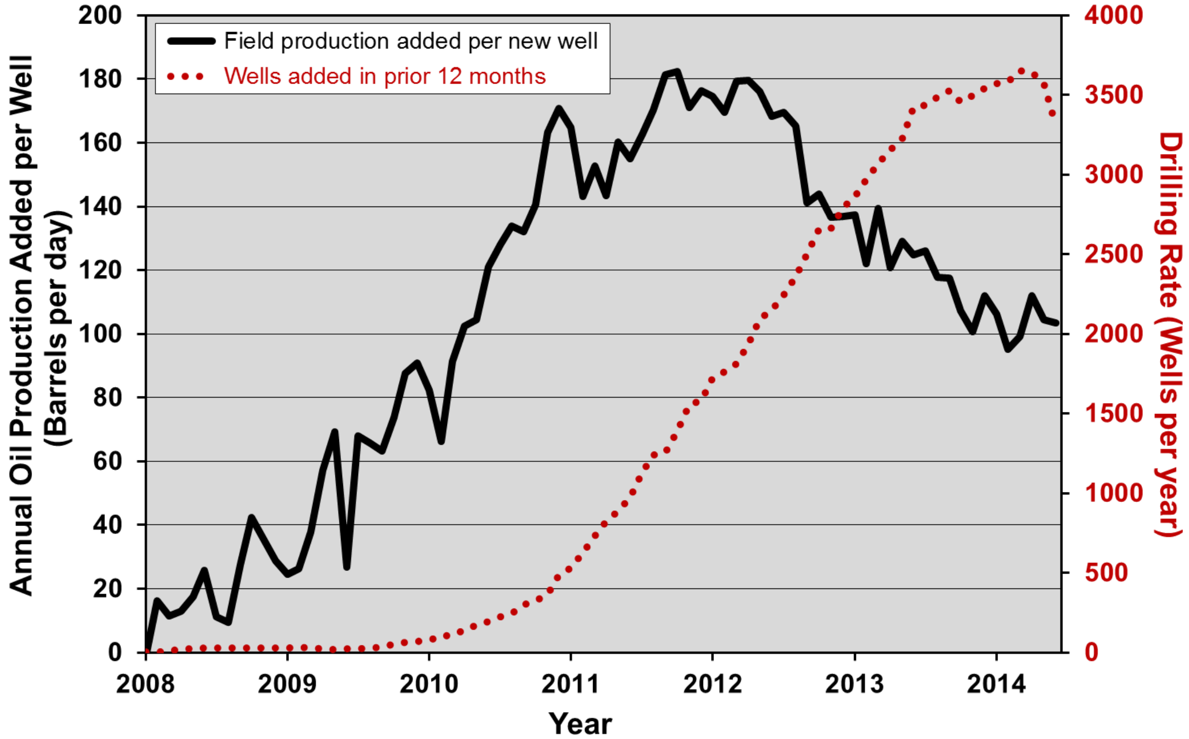


Figure 2-32. Annual oil production added per new well and annual drilling rate in the Eagle Ford play, 2008 through 2014, 2008 to 2014.[59]

[59] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

2.3.2.1 Well Decline

The first key fundamental in determining the life cycle of Eagle Ford production is the *well decline rate*. Eagle Ford wells exhibit high decline rates in common with all shale plays. Figure 2-33 illustrates the average decline profile of Eagle Ford horizontal wells, both for oil alone and for oil and gas on a "barrels of oil equivalent" basis. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The average decline rate over the first three years of well life for oil and gas is 79% and 80%, respectively.

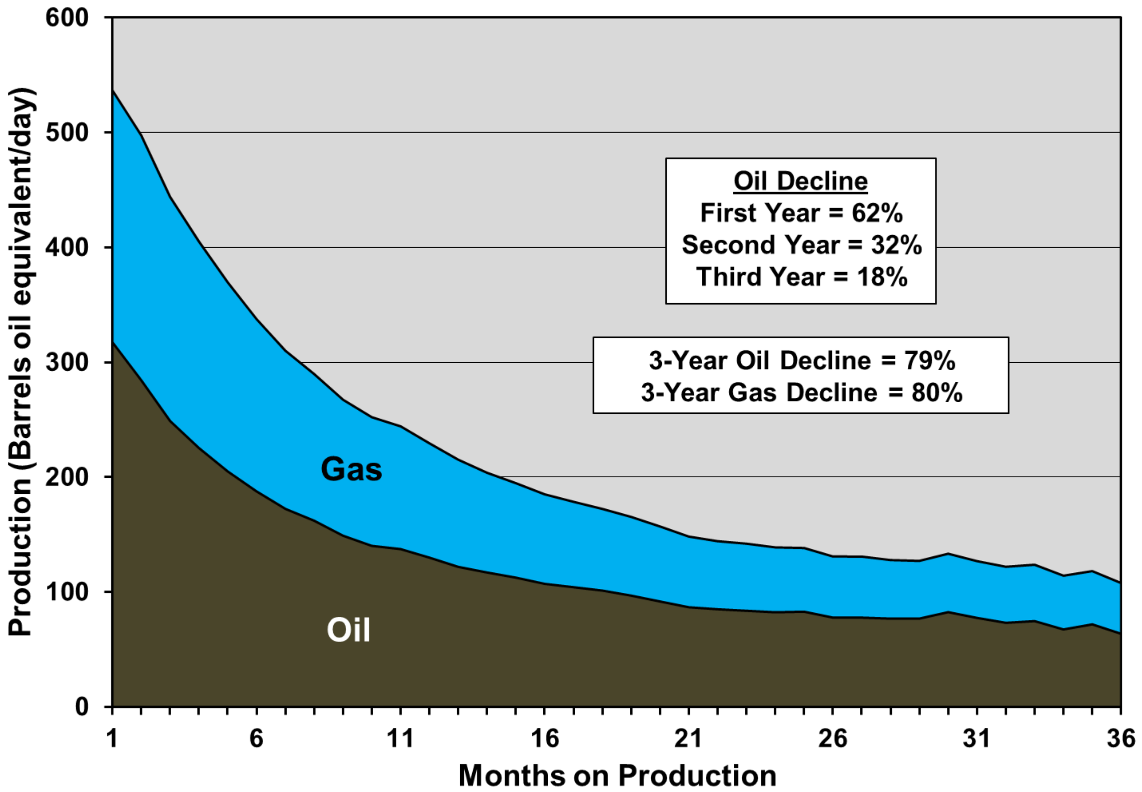


Figure 2-33. Average decline profile for horizontal tight oil and shale gas wells in the Eagle Ford play.[60]

Gas has been converted to barrels of oil on an energy equivalent basis. Decline profile is based on all horizontal wells drilled since 2009.

[60] Data from Drillinginfo retrieved May 2014.

2.3.2.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost in a year without more drilling. Figure 2-34 illustrates oil production from the 5,800 horizontal wells spudded (i.e., drilling was started) prior to 2013, and the 4,964 wells actually producing prior to 2013 (wells are being drilled at such a high rate that many wells drilled prior to 2013 were not connected and producing until well into 2013). The first-year decline for producing wells is 38%. This is lower than the well decline rate as the field decline is made up of new wells, declining at high rates, and older wells, declining at lesser rates. As will be shown later, a field decline of 38% requires 2,285 wells to offset at current production levels, representing capital input of $18.3 billion assuming an average well cost of $8 million.

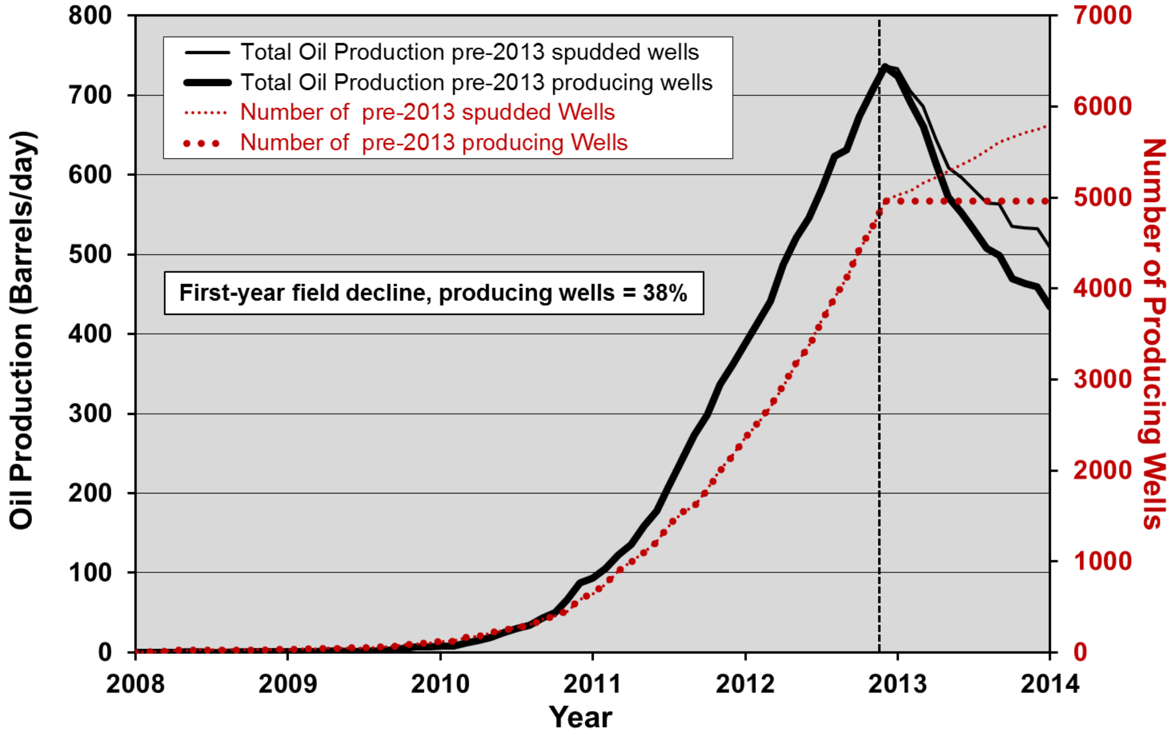


Figure 2-34. Production rate and number of horizontal tight oil wells in the Eagle Ford spudded or producing prior to 2013.[61]

Many of the spudded wells were not connected and producing until well into 2013. In order to offset the 38% field decline rate, 2,285 new wells per year producing at 2013 levels would be required.

[61] Data from Drillinginfo retrieved May 2014.

Figure 2-35 illustrates the same analysis on a "barrels of oil equivalent" basis to account for the large amounts of gas also produced. Field decline for wells producing prior to 2013 is 42% in the first year on a barrels oil equivalent basis, and for gas on a standalone basis is 47%.

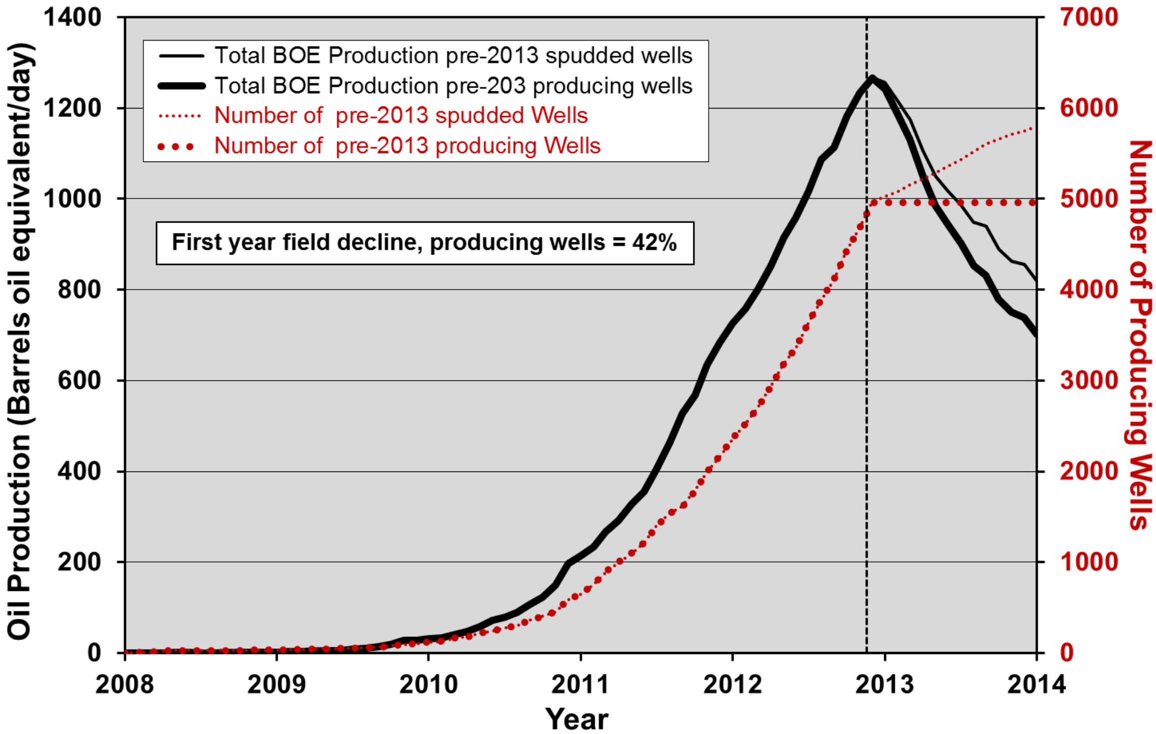


Figure 2-35. Production rate and number of horizontal tight oil wells in the Eagle Ford spudded or producing prior to 2013, including gas on a "barrels of oil equivalent" basis.[62]

Field decline is 42% per year for oil and gas on a "barrels of oil equivalent" basis, and for gas on a standalone basis is 47%.

[62] Data from Drillinginfo retrieved May 2014.

2.3.2.3 Well Quality

The third key fundamental is the trend of *average well quality* over time. As noted earlier, petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, which along with multi-well pad drilling has reduced well costs. It is, however, approaching the limits of diminishing returns and improvements in average well quality are flat to very slightly increasing at best.

Figure 2-36 illustrates production rate trends in oil, gas and "barrels of oil equivalent" from 2009 to 2013 based on the average first year production of wells. On a barrels of oil equivalent basis (BOE) there has been no improvement since 2012, whereas there has been a 4% improvement in oil productivity and a decrease in gas productivity. These trends reflect the shift in operator emphasis to liquids production with the low price of gas, focusing drilling in the oil window of the Eagle Ford, as well as concentrating on the sweet spots defined in the initial wave of drilling. The lack of improvement on a BOE basis suggests better technology is having a very limited, if any, effect; there appears to still be room for significant numbers of new wells in sweet spots, so operators have not yet been forced to move into lower quality parts of the play.

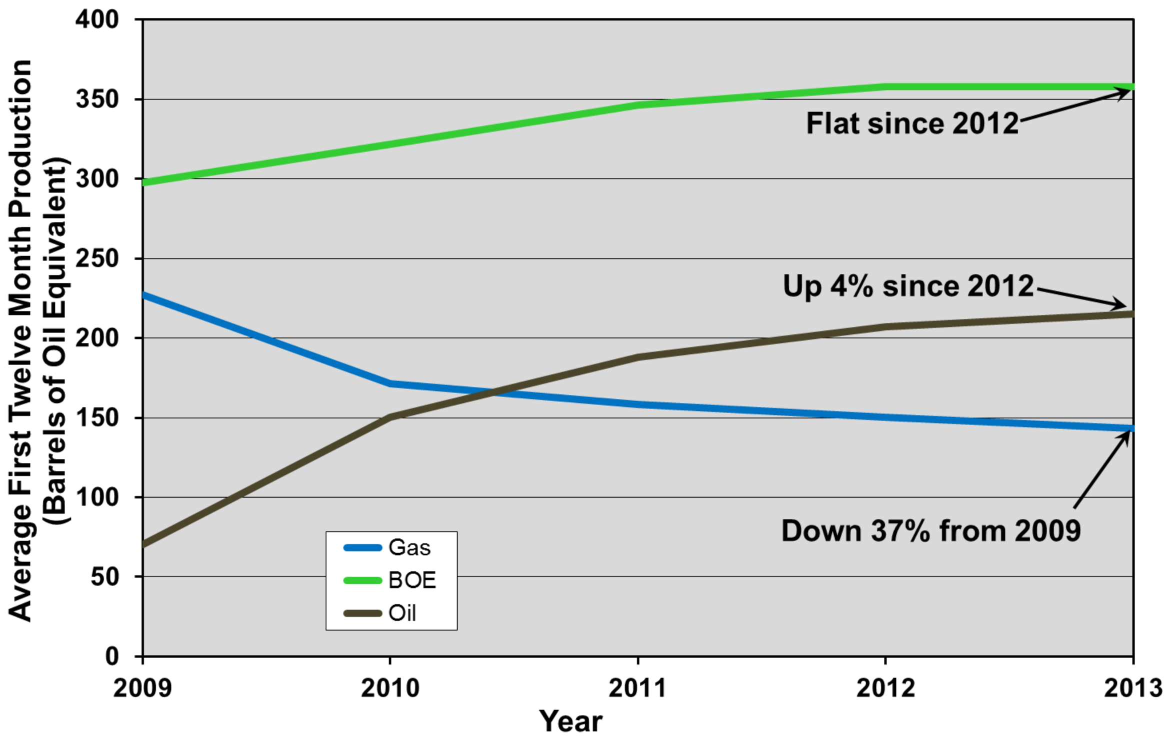


Figure 2-36. Average first year production rates for Eagle Ford wells from 2009 to 2013.[63]

Total production on a "barrels of oil equivalent" basis is unchanged since 2012, whereas oil has risen slightly and gas has fallen. This reflects the focus on liquids production over gas and the concentration of drilling in the oil window of the field, as well as the focus on proven sweet spots, along with likely limited gains from technological improvements in the most recent year.

[63] Data from Drillinginfo retrieved May 2014.

Another measure of well quality is cumulative production and well life. Figure 2-37 illustrates the cumulative production of all oil wells that were producing in the Eagle Ford as of March 2014. Eighty-nine percent of these wells are less than 3 years old, and knowing that production will be down nearly 80% after 3 years, their economic lifespan is uncertain. Although it can be seen that there are a few very good wells that recovered more than 400,000 barrels of oil in the first few years, and undoubtedly were great economic successes, the average well has produced just 72,145 barrels over a lifespan averaging 20 months. Less than 1% of these wells are more than 5 years old. The lifespan of wells is another key parameter as many operators assume a minimum life of 30 years and longer—this is conjectural at this point given the lack of long-term well-performance data.

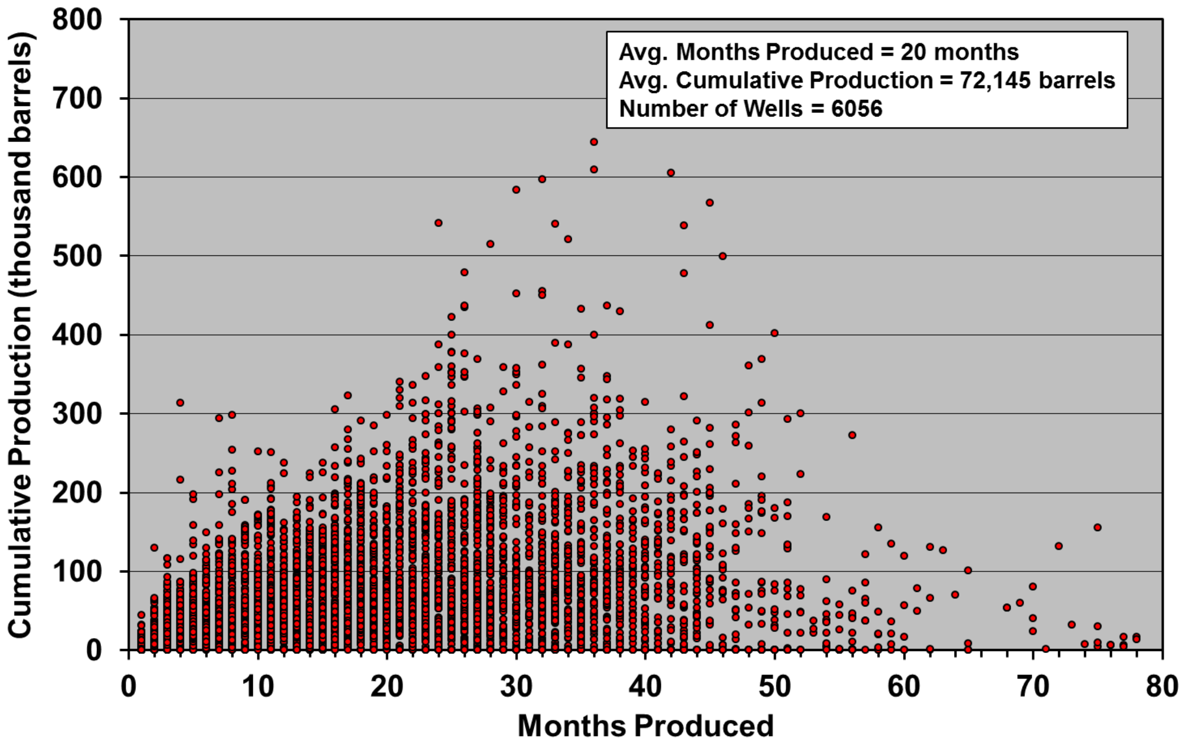


Figure 2-37. Cumulative oil production and months produced for Eagle Ford wells that were producing as of March 2014.[64]

Very few wells are greater than five years old, with a mean age of 20 months and a mean cumulative recovery of 72,145 barrels.

[64] Data from Drillinginfo retrieved September 2014. Note that only leases with one well and individual wells are included in this figure (Texas has a practice of lumping production from multi-well leases with production from individual wells).

Cumulative production of course depends on how long a well has been producing, so looking at young wells in not necessarily a good indication of how much oil these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP) which is often focused on by operators. Figure 2-38 illustrates the average daily output over the first six months of production (six-month IP) for all oil wells in the Eagle Ford play. Again, as with cumulative production, there are a few exceptional wells—4% of wells produced more than 600 barrels per day over the first six months—but the average for all wells drilled between 2008 and 2014 is just 262 barrels per day. The trend line on Figure 2-38 shows the average over time, which has been increasing slightly over the period, owing to both better technology and the focus of drilling on sweet spots. Figure 2-28 and Figure 2-29 illustrate the distribution of IPs in map form.

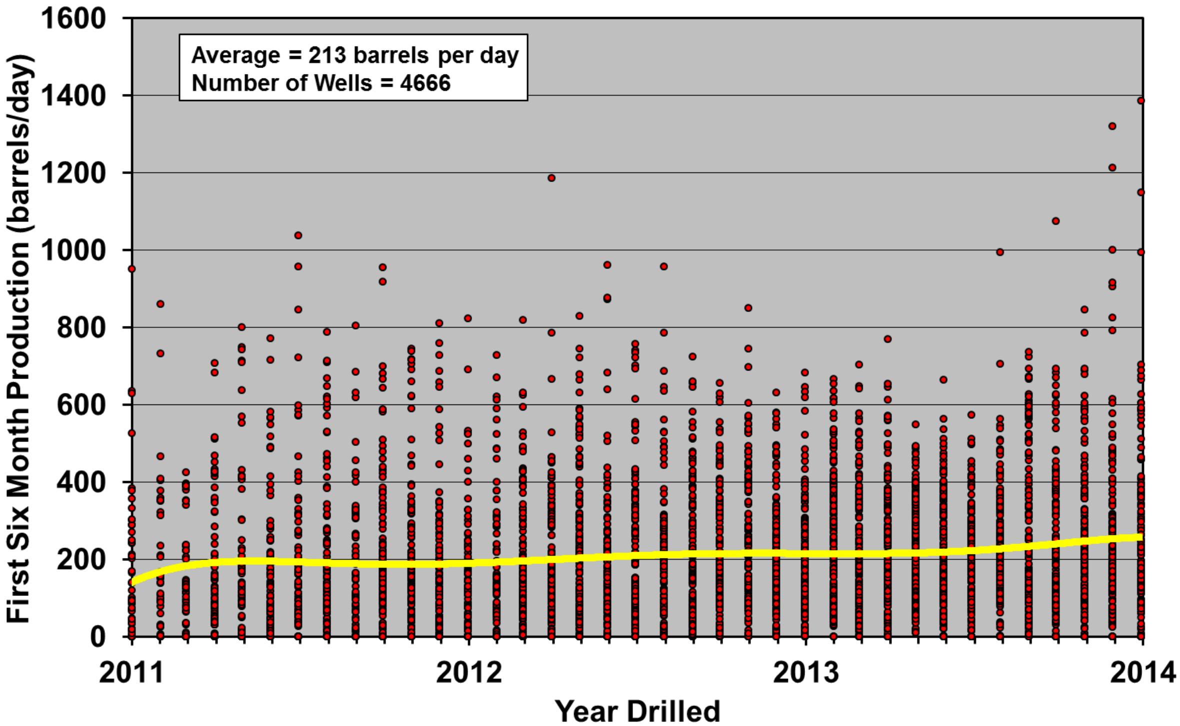


Figure 2-38. Average oil production over the first six months for all wells drilled in the Eagle Ford play.[65]

Although there are a few exceptional wells, the average well produced 213 barrels per day over this period. The trend line indicates variation in mean productivity over time.

[65] Data from Drillinginfo retrieved September 2014. Note that only leases with one well and individual wells are included in this figure (Texas has a practice of lumping production from multi-well leases with production from individual wells).

Drilling has focused on liquids-rich parts of the play given the low price of gas in recent years, however the Eagle Ford still produces large amounts of gas which adds to the economic viability of wells. Figure 2-39 illustrates the average production of wells over the first six months on a "barrels of oil equivalent" basis (converting natural gas to its oil equivalent on an energy basis—6000 cubic feet of natural gas equals one barrel of oil). The trend line in this case, combining oil and gas, is essentially flat over the 2011 through 2014 period, indicating technological improvements are not improving well productivity.

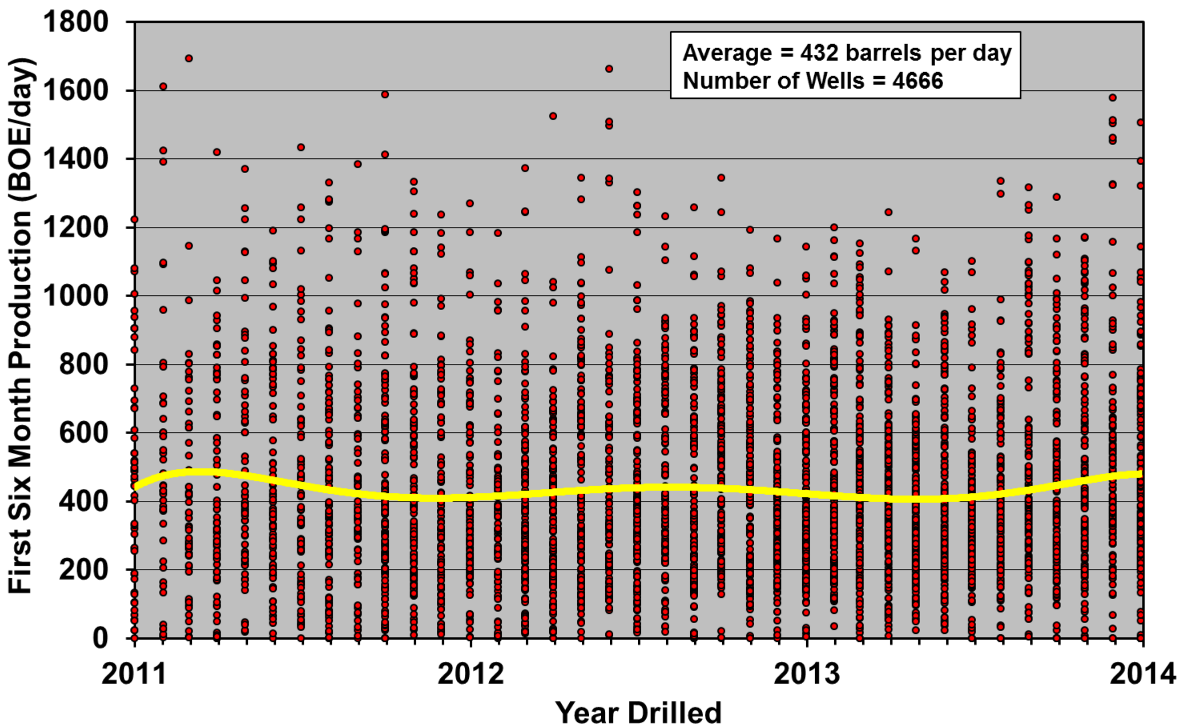


Figure 2-39. Average oil and gas production over the first six months for all wells drilled in the Eagle Ford play on a barrels of oil equivalent basis.[66]

Although there are a few exceptional wells, the average well produced 432 barrels of oil equivalent per day over this period.

[66] Data from Drillinginfo retrieved September 2014. Note that only leases with one well and individual wells are included in this figure (Texas has a practice of lumping production from multi-well leases with production from individual wells).

Different counties in the Eagle Ford display markedly different well production rate characteristics which are critical in determining the most likely production profile in the future. Figure 2-40, which illustrates oil production over time by county, shows that the top three counties produce 51% of the total, the top six produce 81% and the remaining 22 counties produce just 19%. Three years of widespread drilling (see Figure 2-41 for number of wells drilled per county) have not resulted in significant production increases outside the top six counties.

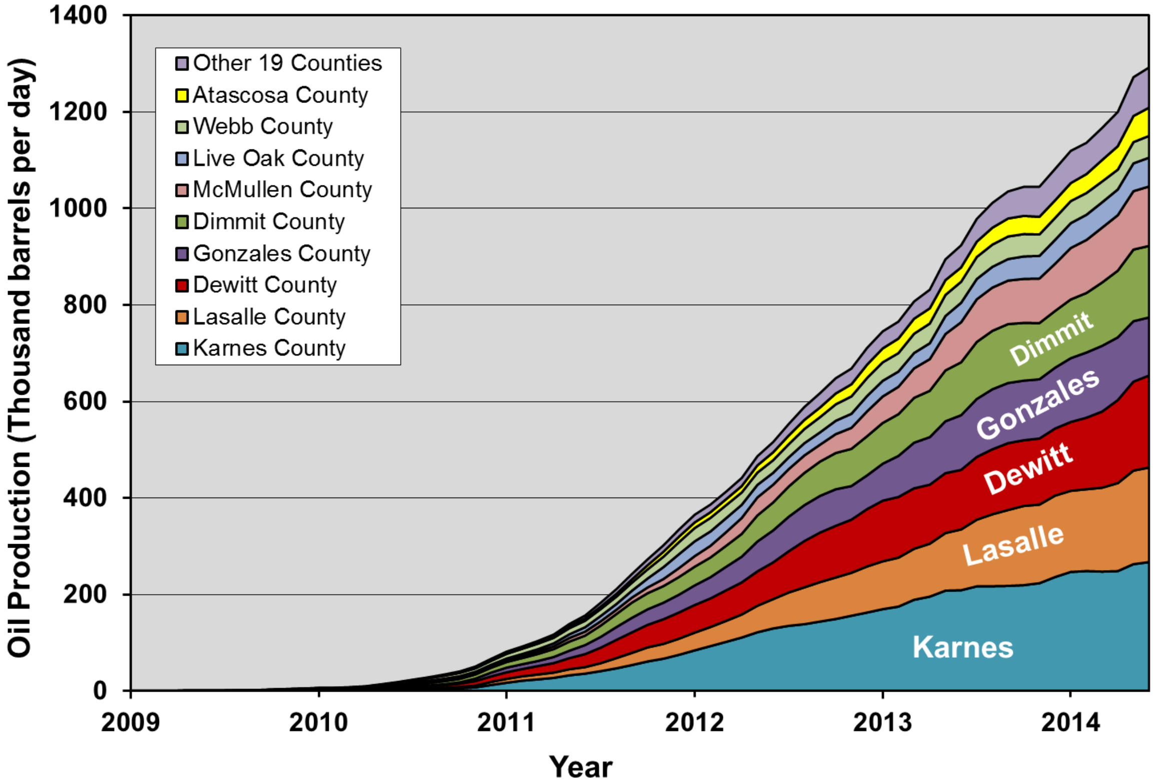


Figure 2-40. Oil production by county in the Eagle Ford play, 2009 through 2014.[67]
Eighty-one percent of production came from just six counties in mid-2014.

[67] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 2-41, the top three counties have produced 51% of the oil and the top six have produced 81%.

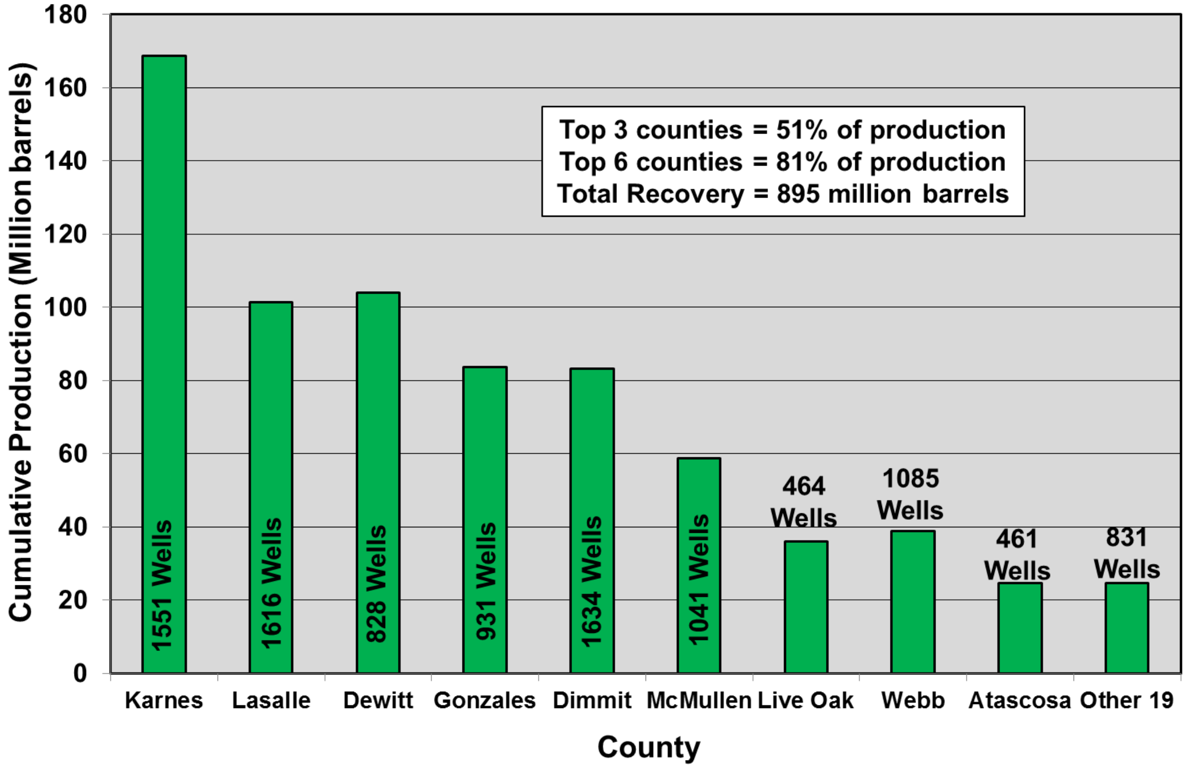


Figure 2-41. Cumulative oil production by county in the Eagle Ford play through 2014.[68]

The top six counties have produced 81% of the 895 million barrels produced to date. Production is growing in all counties.

[68] Data from Drillinginfo retrieved September 2014.

Approximately 39% of the energy produced from the Eagle Ford is in the form of natural gas, making the field one of the nation's top five gas fields (see the Eagle Ford section in *Part3: Shale Gas* of this report for a full discussion). The Eagle Ford currently produces 4.9 billion cubic feet per day and has produced nearly four trillion cubic feet since 2009. As with oil, gas production is concentrated in a few counties, but these tend to be different counties than for oil given the segregation of the play into oil and gas windows. Webb County, for example, produces less than 4% of the play's oil but produces 25% of its gas. Figure 2-42 illustrates gas production from the play since 2009 by county. In 2014, the top three counties produced 54% of the gas and the top six produced 87%.

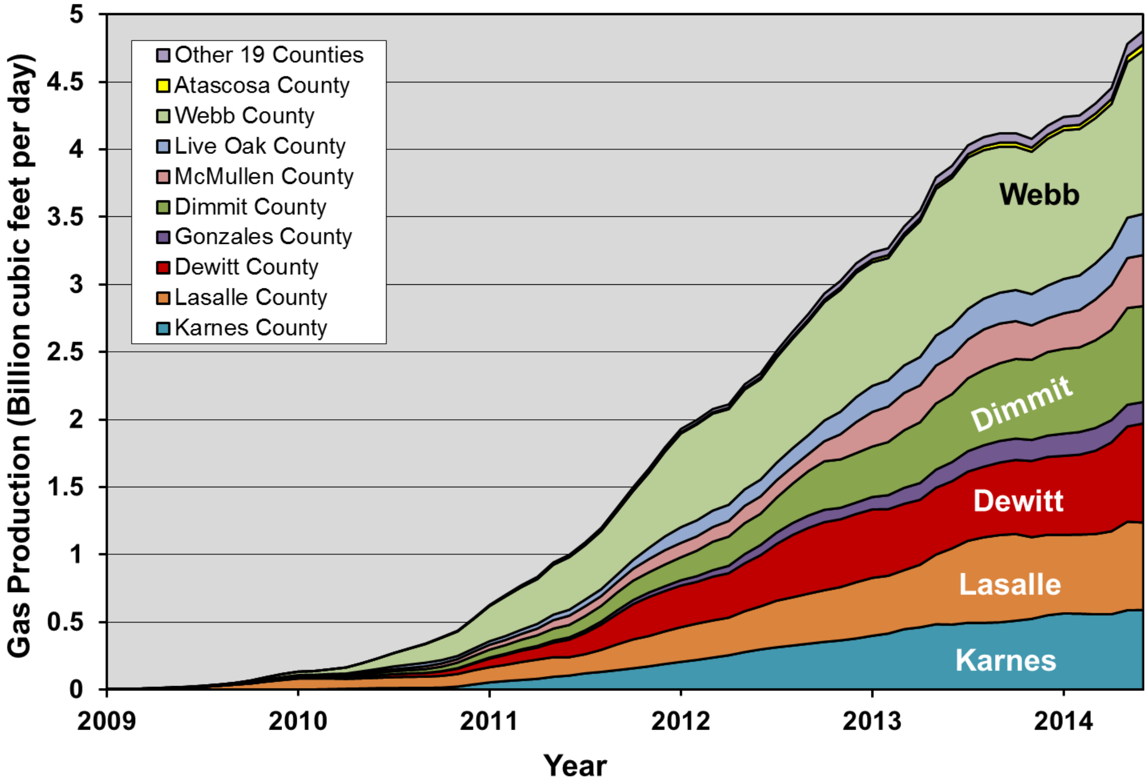


Figure 2-42. Gas production by county in the Eagle Ford play, 2009 through 2014.[69]

Eighty-seven percent of production came from just six counties as of mid-2014. For ease of comparison, the counties in this figure are sorted in the same order as in Figure 2-40, i.e., by *oil* production.

[69] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

Figure 2-43 illustrates cumulative gas production from the play as of mid-2014. The top three counties have produced 58% of the gas and the top six have produced 89%.

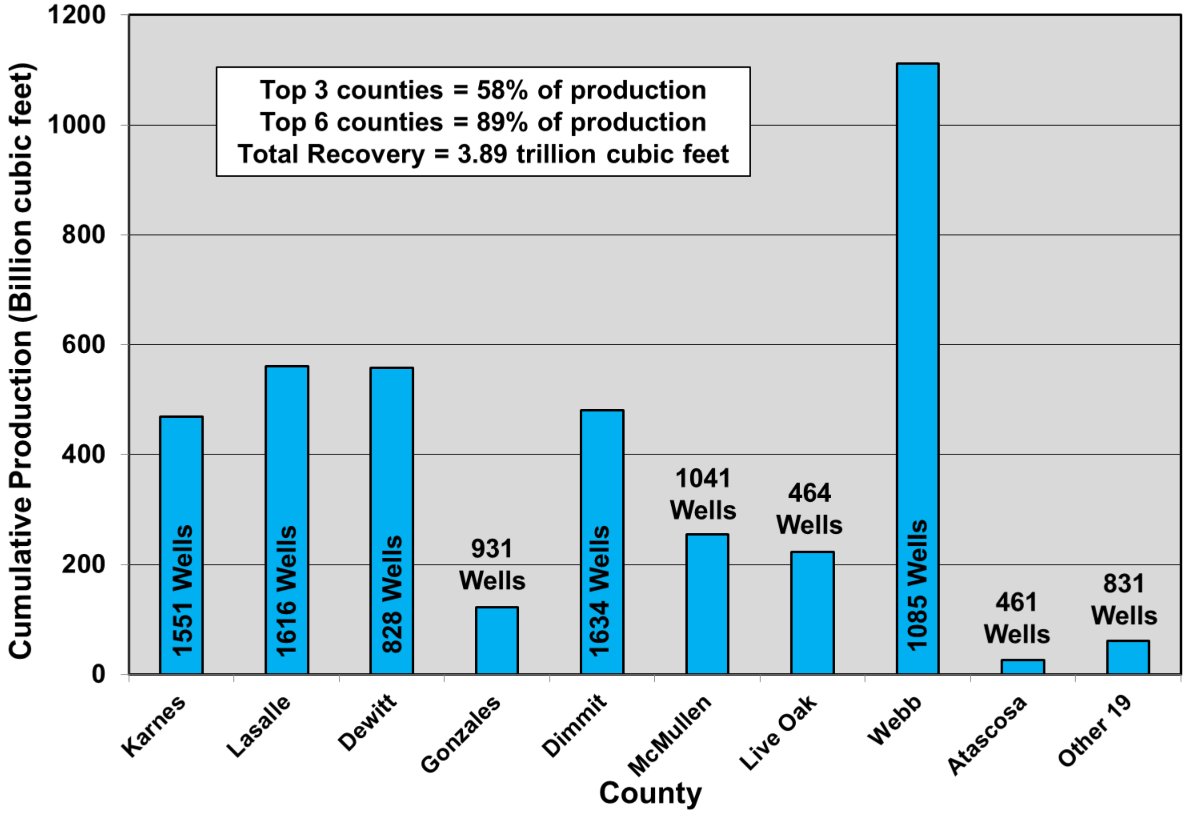


Figure 2-43. Cumulative gas production by county in the Eagle Ford play through 2014.[70]
The top six counties have produced 89% of the 3.89 trillion cubic feet produced to June 2014.

[70] Data from Drillinginfo retrieved September 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost in the order of $8 million each,[71] not including leasing costs and other expenses. The areas of highest quality—the "core" or "sweet spots"—have now been well defined, both for oil and gas. Figure 2-44 illustrates average well decline profiles by county which are a measure of well quality. As can be seen, the decline profiles from the top four counties are all above the Eagle Ford average, hence these counties are attracting the bulk of the drilling and investment.

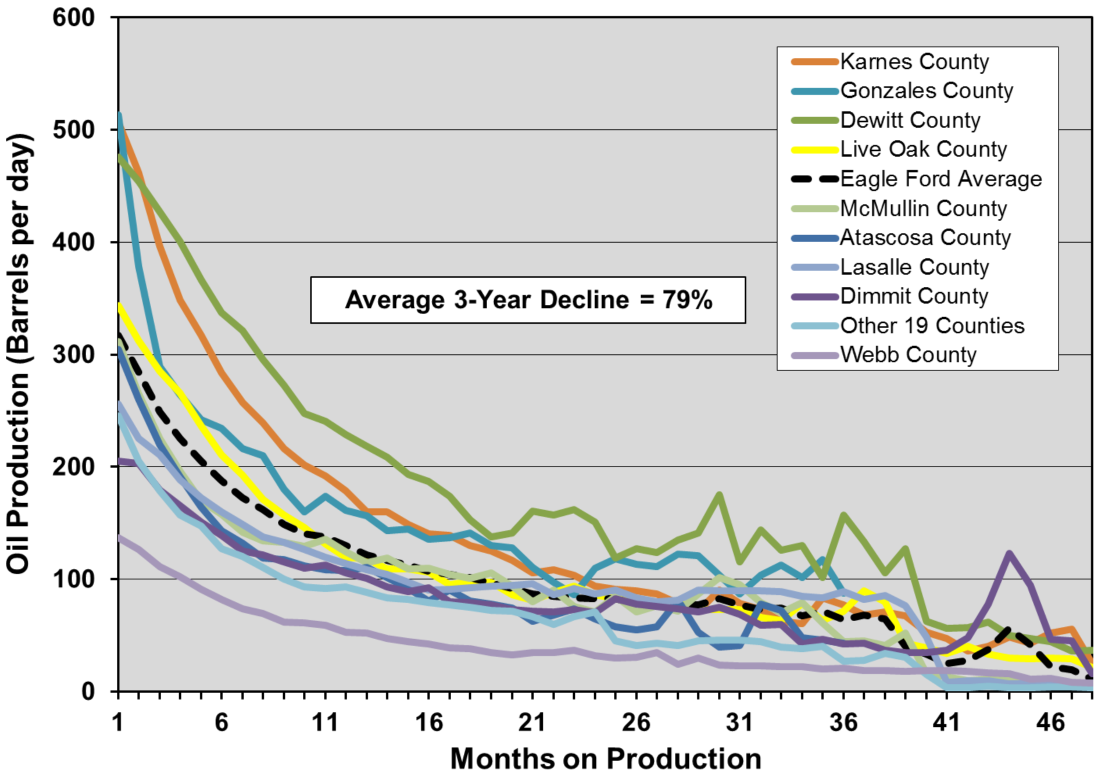


Figure 2-44. Average oil well decline profiles by county for the Eagle Ford play.[72]

The top four counties, which have produced much of the oil in the Eagle Ford, are clearly superior compared the play average and the other 23 counties. Well decline profiles are based on horizontal wells drilled since 2009.

[71] Trey Cowan, "Costs for Drilling The Eagle Ford," *Rigzone*, June 20, 2011, https://www.rigzone.com/news/article.asp?a_id=108179.
[72] Data from Drillinginfo retrieved May 2014.

Figure 2-45 illustrates average well decline profiles on a "barrels of oil equivalent" basis which includes the energy value of natural gas. Five counties are above the Eagle Ford average. Although four of these five are also the top four for oil production, Webb County is the second highest county on an energy output basis due to its prolific natural gas output, whereas is it ranks at the bottom for oil output.

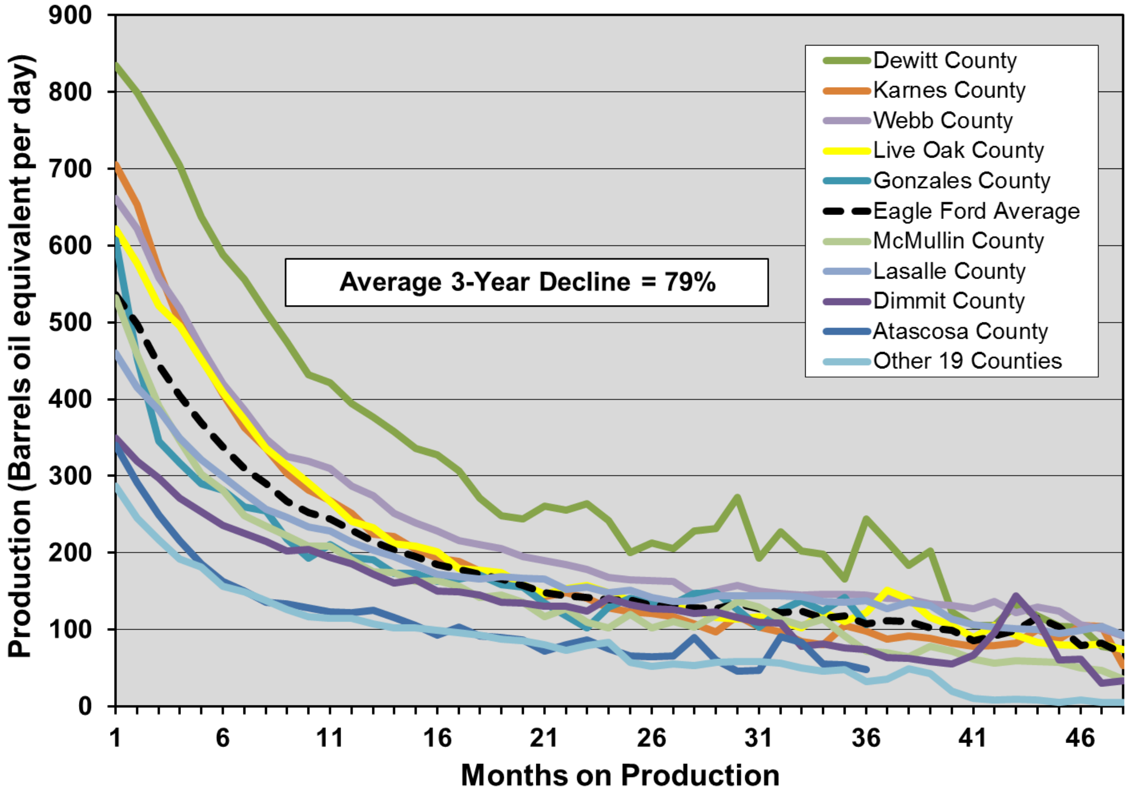


Figure 2-45. Average well decline profiles on a "barrels of oil equivalent" basis including the energy of natural gas produced by county for the Eagle Ford play.[73]

Although the top five counties include the top four for oil, Webb County has moved up to number two on an energy output basis, whereas it ranks at the bottom for oil production. Well decline profiles are based on horizontal wells drilled since 2009.

Another measure of well quality is "estimated ultimate recovery" (EUR), the amount of oil a well will recover over its lifetime. To be clear, no one knows what the lifespan of an Eagle Ford well is, given that few of them are more than five years old. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 2-44 and Figure 2-45, assuming well life spans of 30-50 years by comparison to conventional wells, but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Eagle Ford. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 2-44 and Figure 2-45, which show that wells exhibit steep initial decline rates with progressively more gradual decline rates over the first three years, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

[73] Data from Drillinginfo retrieved May 2014.

Figure 2-46 illustrates theoretical EURs per well by county for the Eagle Ford; these range from 101,000 to 531,000 barrels per well. This compares to EURs of 97,000 to 223,000 barrels per well assumed by the EIA (the EIA EURs are not broken down by county and include large areas of limited prospectivity).[74] EURs in the top three counties are nearly 100% higher than in the lowest 22 counties of the play. The steep well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 46% and 56% of an average well's lifetime production occurs in the first three years.

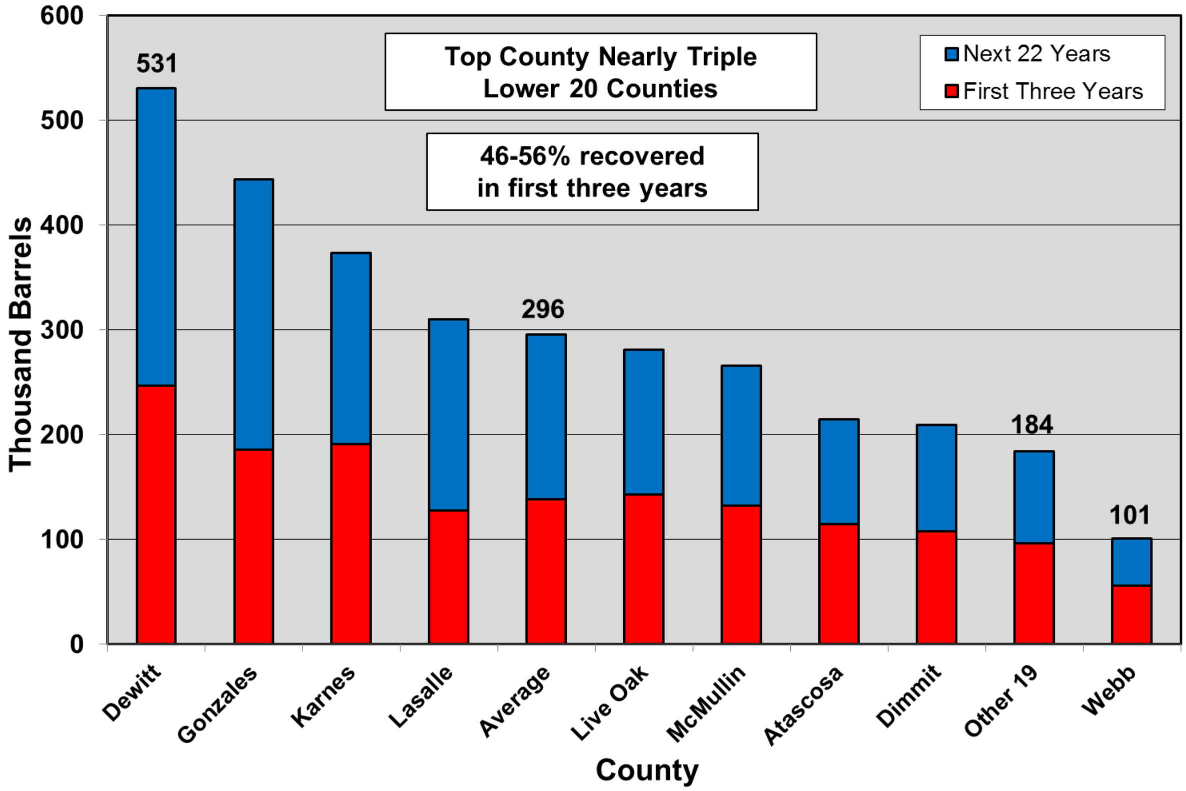


Figure 2-46. Estimated ultimate recovery of oil per horizontal well by county for the Eagle Ford play.[75]

EURs are based on average well decline profiles (Figure 2-44) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 25 years, as are the decline rates at the end of well life. The steep decline rates mean that most production occurs early in well life.

[74] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

[75] Data from Drillinginfo retrieved May 2014.

Figure 2-47 illustrates theoretical EURs by county on a “barrels of oil equivalent” basis showing the split between oil and gas by county. The average well has an EUR of nearly 500,000 barrels oil equivalent, with Dewitt, the top county, more than triple the lowest 20 counties.

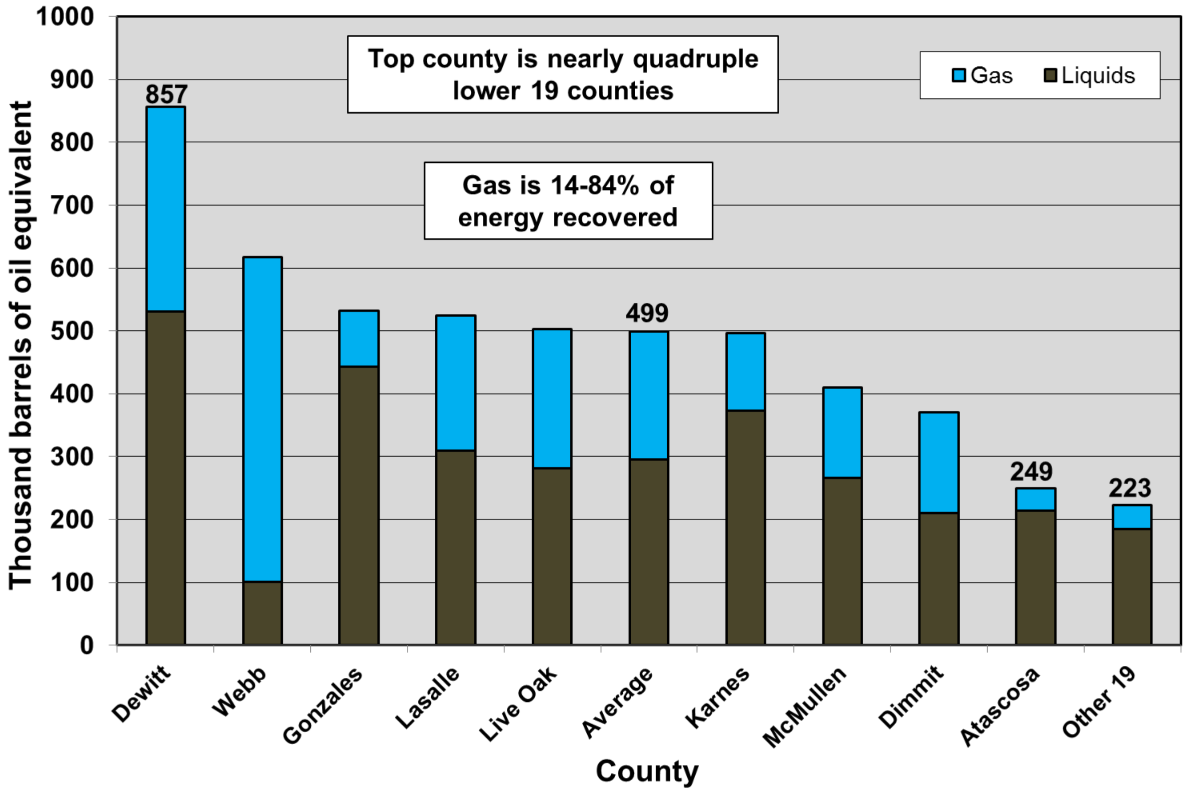


Figure 2-47. Estimated ultimate recovery on a “barrels of oil equivalent” basis, including the energy value of gas, by county for the Eagle Ford play.[76]

EURs are based on average well decline profiles (Figure 2-45) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 25 years, as are the decline rates at the end of well life. Gas comprises 14% to 84% of the energy produced with an average of about 39%.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the field decline rate and the average well’s first-year production rate, we can calculate the number of wells that need to be drilled each year in order to offset field decline and maintain production. Given that drilling is currently focused on the highest quality counties, the average first-year production rate per well will fall as drilling moves into lower quality counties over time as the best locations are drilled off. As average well quality falls, the number of wells that must be drilled to offset field decline must rise, until the drilling rate can no longer offset decline and the field peaks.

[76] Data from Drillinginfo retrieved May 2014.

Figure 2-48 illustrates the average first year oil production rate of wells by county over the 2009 to 2013 period. Gains are evident in several counties although Dewitt, the most productive county, is in decline. Only three counties exceed the play average. The average increase in productivity for the play as a whole is just 4% over 2012, suggesting that technological improvements are approaching the limits of diminishing returns. Much of the observed improvement is likely from the shift of drilling from gas prone to oil prone portions of counties. Future technology improvements are unlikely to postpone for long the inevitable decline in average overall well quality as drilling moves into lower quality counties.

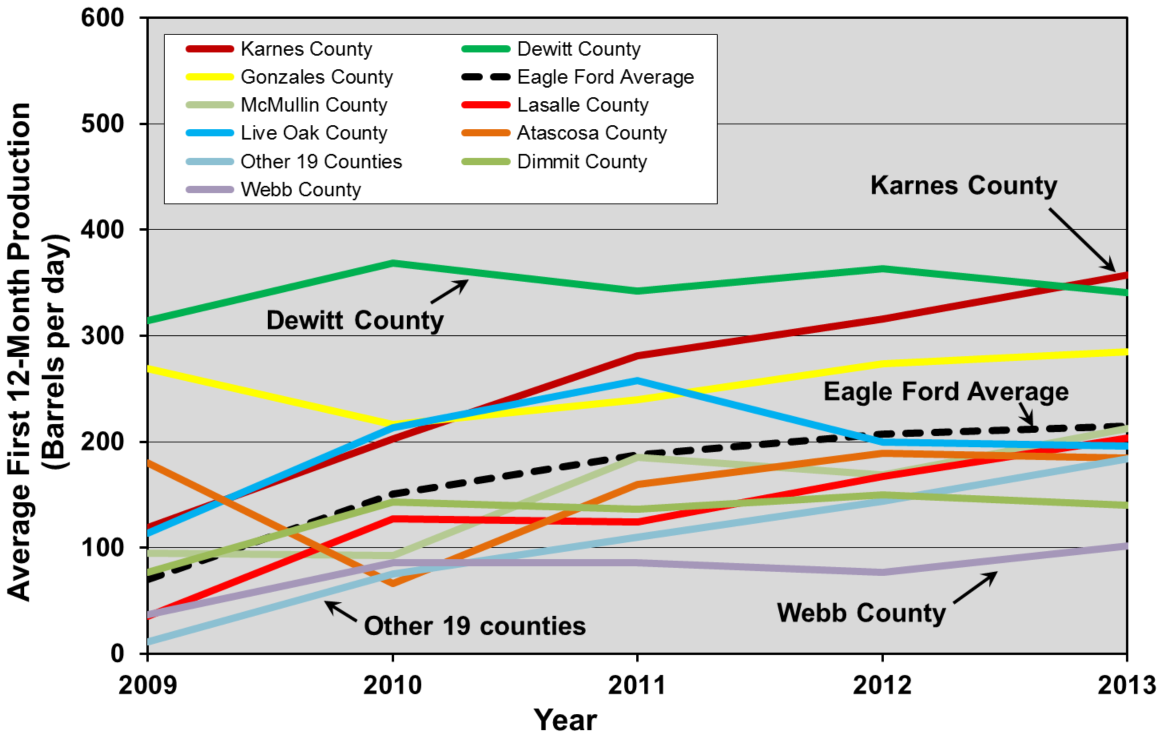


Figure 2-48. Average first-year oil production rates of wells by county for the Eagle Ford play, 2009 to 2013.[77]

Well quality is rising most rapidly in Karnes County, which has the second highest well count. Average first year oil production rates rose 4% over 2012.

[77] Data from Drillinginfo retrieved May 2014.

Figure 2-49 illustrates the average first year oil and gas production rate of wells by county on a "barrels of oil equivalent" basis over the 2009 to 2013 period. Gains are evident in several counties although Dewitt, the most productive county, is in decline, and the overall average for the play is unchanged over 2012, suggesting technological improvements are not making much difference overall.

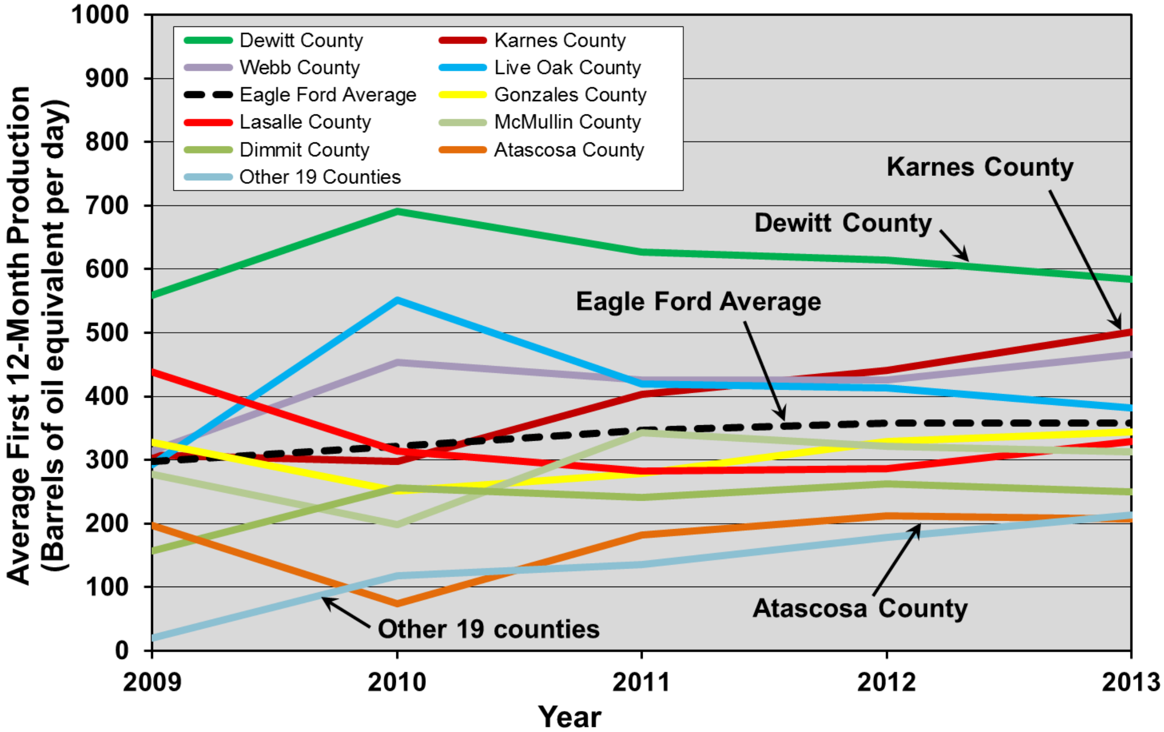


Figure 2-49. Average first-year oil and gas production rates of wells on a "barrels of oil equivalent" basis by county for the Eagle Ford play, 2009 to 2013.[78]

Average first-year production rates were unchanged in 2013 compared to 2012.

[78] Data from Drillinginfo retrieved May 2014.

2.3.2.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Eagle Ford, a function of (a) the size of the area worth drilling and (b) the density of drilling that will likely occur. As in the Bakken, this is hotly debated in investor presentations.

Determining the likely density at which operators will drill wells requires consideration of both the geology of the play and the mechanics of hydraulic fracturing. Typical wells in the Eagle Ford have horizontal laterals of 5,000-7,000 feet in length with 20 or more frack stages. The EIA suggests that the area may be drilled at a density of 6 wells per square mile,[79] which would space horizontal laterals at 880 feet from each other. Companies like Marathon claim that spacing in core areas can be reduced to 16 wells per square mile in its pilots (40-acre spacing).[80] This would place horizontal laterals 350 feet apart, implying that frack jobs on wells only effectively drain less than 200 feet from a well.

This seems very optimistic given studies on well interference discussed earlier (section 2.3.1.4) showing that interference may occur with wells separated by less than 2,000 feet in the Bakken.[81] There has been no compelling evidence presented to suggest that 40-acre spacings in the Eagle Ford will not cannibalize production from adjacent wells, meaning that such attempts will not increase ultimate oil and gas recovery, although they may temporarily increase production.

Determining the area actually conducive to drilling is comparatively straightforward. After years of exploration and thousands of wells drilled, operators have delineated the limits of the play and focused their efforts on those areas with proven potential; thus by identifying the farthest-lying wells with little to no production as the likely edge of the play, and estimating the size of the area within that edge which is clearly attracting industry interest, the functional area of the Eagle Ford play can be calculated. By this method, the area likely to be conducive to drilling is approximately 7,200 square miles (see Figure 2-28).

Based on the above parameters, and given the fact that much of the area covered by the Eagle Ford is of considerably lower quality than the top few counties, an estimate of 6 wells per square mile may be reasonable for the whole area, allowing for a higher density in core areas and a lower density in outlying lower quality areas. This translates to approximately 43,200 potential wells if drilled at a density of 6 wells per square mile (compared to EIA's estimated 66,987 locations, determined from the product of the EIA's play area and well density). As more than 10,500 wells have been drilled to date, this means that approximately 32,800 wells remain to be drilled. Of course, these estimates assume that the entire designated area is available, and do not account for parks, towns, rivers, reservoirs, and other areas not conducive to drilling. A more conservative but possibly more realistic calculation would include a "risk" that 20% of the remaining play area will be undrillable. This reduces the remaining number of potential wells to approximately 26,200 which, coupled with wells already drilled, puts the total well count when the play is completely finished at 35,900. Either way, the Eagle Ford play could experience somewhere between three and four times the number of wells drilled to date.

[79] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[80] Marathon Investor Presentation, December 11, 2013, http://files.shareholder.com/downloads/AMDA-DZ30I/2909841818x0x713050/bf6626c0-3865-4e94-a4d4-6d47103dcc6d/Analyst_Day_Final_without_notes_v2.pdf.
[81] Kevin Thuot, "There Will Be Blood: Well Spacing & The Bakken Shale Oil Milkshake," DrillingInfo, November 26, 2013, http://info.drillinginfo.com/well-spacing-bakken-shale-oil.

2.3.2.5 Rate of Drilling

The fifth key fundamental is the *rate of drilling*. As noted earlier, the Eagle Ford play has a field decline of 38% per year (for oil), meaning that 38% of production has to be replaced with new wells each year to keep production flat. As the amount of oil produced from an average well in its first year of production is known from the data, the number of wells needed to offset field production decline each year at a given production level can be easily calculated. For the Eagle Ford at current production levels some 2,285 wells must be drilled each year to keep production flat. Since drilling rates in the Eagle Ford are now at about 3,550 wells per year, production will keep growing as long as these rates are sustained—until drilling locations run out. However, the higher production grows, the more wells are needed to offset the field decline. And as drilling moves into lower quality parts of the play, even more wells will be needed, for as illustrated above (Figure 2-48), well quality in most counties is significantly lower than in the best three.

2.3.2.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Eagle Ford play were developed to illustrate the effects of changing the rate of drilling.

The projections are given in two cases, differentiated by the number of drilling locations:

1. An "Optimistic Case" of 100% of the play area being drillable, at 6 wells per square mile.
2. A "Realistic Case" of 80% of the remaining play area being drillable (i.e., the play is "risked" at 80% to account for undrillable areas like parks, towns, rivers, etc.), at 6 wells per square mile.

Each case includes three scenarios, differentiated by the rate of drilling:

1. MOST LIKELY RATE scenario: Drilling continues at the current rate of 3,550 wells per year and then declines to 2,000 wells per year as drilling moves into the lower quality counties.
2. EXPANDED RATE scenario: Drilling continues at the current rate of 3,550 wells per year and held constant until locations run out.
3. FASTEST RATE scenario: Drilling is increased to 4,000 wells per year and held constant until locations run out.

The critical parameters used for determining production rates in these scenarios are given in Table 2-2.

Parameters	Counties										Total
	Atascosa	Dewitt	Dimmit	Gonzales	Karnes	Lasalle	Live Oak	McMullen	Webb	Other 19	
Oil Production Jan 2014 (Kbbl/d)	58.6	190.8	148.3	120.3	267.1	196.0	59.7	123.2	45.2	83.2	1292.2
Gas Production Jan 2014 (Kbbl/d)	7.9	122.3	118.3	26.5	98.3	107.9	50.8	63.0	201.5	16.5	813.1
Gas Production Jan 2014 (Bcf/d)	0.0	0.7	0.7	0.2	0.6	0.6	0.3	0.4	1.2	0.1	4.9
Oil % of Field Production	4.5	14.8	11.5	9.3	20.7	15.2	4.6	9.5	3.5	6.4	100.0
BOE % of Field Production	3.2	14.9	12.7	7.0	17.4	14.4	5.3	8.8	11.7	4.7	100.0
Gas % of Field Production	1.0	15.0	14.6	3.3	12.1	13.3	6.3	7.7	24.8	2.0	100.0
Cumulative Oil (million bbls)	32.4	130.3	102.7	101.6	200.0	122.8	43.1	72.5	43.7	46.4	895.5
Cumulative Gas (Bcf)	25.8	557.5	480.1	122.7	468.9	560.3	223.5	254.6	1112.0	60.6	3866.0
Number of Wells	461	828	1634	931	1551	1616	464	1041	1085	831	10442
Number of Producing Wells	441	797	1576	895	1506	1580	458	990	1023	759	10025
Avg. Oil EUR per well (Kbbls)	215	531	210	443	373	310	281	266	101	184	296
Avg. BOE EUR per well (Kbbls)	249	857	371	532	496	524	503	410	618	223	499
Avg. Gas EUR per well (Bcf)	0.2	2.0	1.0	0.5	0.7	1.3	1.3	0.9	3.1	0.2	1.2
Oil Field Decline (%)	50	41	37	33	40	34	40	30	48	27	38
BOE Field Decline (%)	49	44	36	33	42	37	47	45	46	30	42
Gas Field Decline (%)	43	47	34	26	47	41	54	64	46	43	47
Oil 3-Year Well Decline (%)	88	72	79	81	87	68	74	86	86	89	79
BOE 3-Year Well Decline (%)	88	74	82	81	86	72	76	87	79	88	79
Gas 3-Year Well Decline (%)	86	77	82	80	90	78	78	89	77	81	80
Average First Year Oil Production in 2013 (bbl/d)	184.6	340.9	140.0	284.9	357.5	203.3	195.8	212.8	101.4	183.7	214.9
Average First Year BOE Production in 2013 (bbl/d)	207.6	584.0	249.5	344.6	500.9	328.8	381.5	312.4	466.4	213.6	357.9
Average First Year Gas Production in 2013 (mcf/d)	138.4	1459.1	656.9	358.0	860.8	752.9	1113.9	597.3	2190.2	179.7	858.2
Oil New Wells Needed to Offset Field Decline	159	229	392	139	299	328	122	174	214	122	2285
BOE New Wells Needed to Offset Field Decline	157	236	385	141	306	342	136	268	243	140	2470
Gas New Wells Needed to Offset Field Decline	147	236	368	115	322	353	148	405	254	236	2672
Area in square miles	1232	909	1331	1068	750	1489	1036	1113	3357	20000	32285
% Prospective	50	30	90	40	75	80	25	60	30	5	22
Net square miles	616	273	1198	427	563	1191	259	668	1007	1000	7201
Well Density per square mile	0.75	3.04	1.36	2.18	2.76	1.36	1.79	1.56	1.08	0.83	1.45
Additional locations to 6/sq. Mile	3235	808	5553	1632	1824	5531	1090	2966	4958	5169	11162
Population	44911	20097	9996	19807	14824	6886	11531	707	250304	N/A	N/A
Total Wells 6/sq. Mile	3696	1636	7187	2563	3375	7147	1554	4007	6043	6000	43208
Producing Wells 6/sq. Mile	3676	1605	7129	2527	3330	7111	1548	3956	5981	5928	42791

Table 2-2. Parameters for projecting Eagle Ford tight oil production, by county

Optimistic Case

Figure 2-50 illustrates the production profiles of the three drilling rate scenarios in the "Optimistic Case," where 100% of the play area is drillable at six wells per square mile.

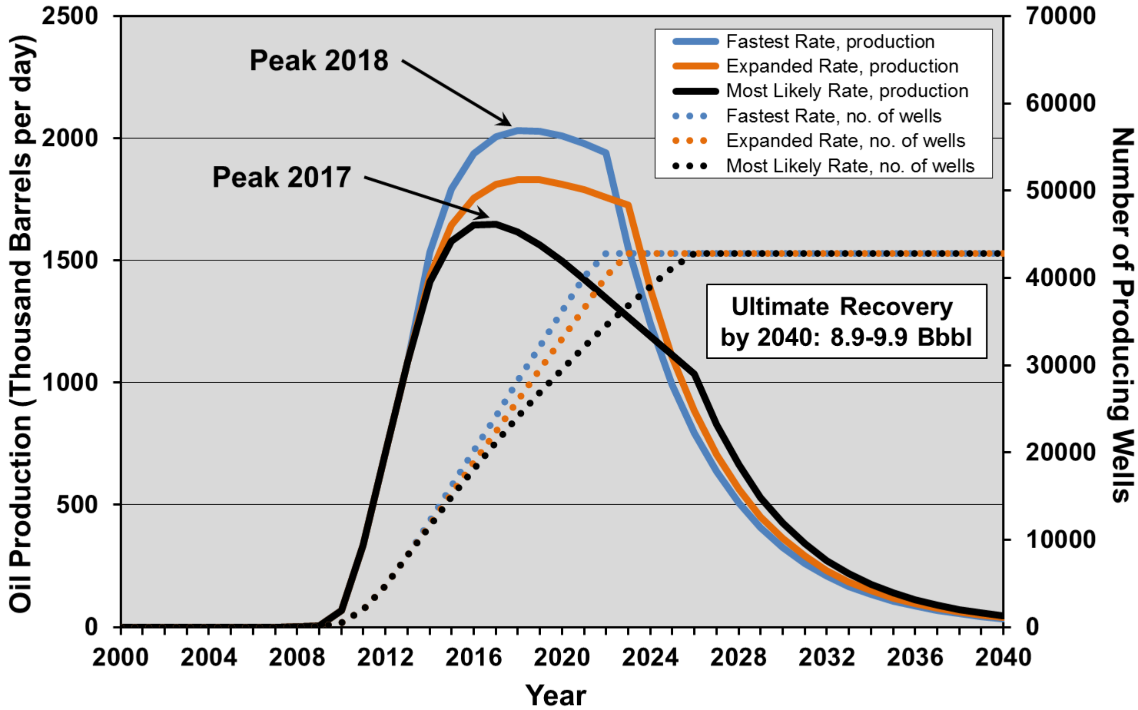


Figure 2-50. Three drilling rate scenarios of Eagle Ford tight oil production, in the "Optimistic Case" (100% of the play area is drillable at six wells per square mile).[82]

"Most Likely Rate" scenario: drilling continues at 3,550 wells/year, declining to 2,000 wells/year.
"Expanded Rate" scenario: drilling continues at 3,550 wells/year, holding constant until locations run out.
"Fastest Rate" scenario: drilling is increased to 4,000 wells/year, holding constant until locations run out.

The drilling rate scenarios in this case have the following results:

1. MOST LIKELY RATE scenario: Peak production occurs in 2017 at 1.65 MMbbl/d. Drilling continues until 2026, and total oil recovery by 2040 is 8.9 billion barrels.

2. EXPANDED RATE scenario: Peak production occurs in 2018 at 1.83 MMbbl/d. Drilling continues until 2023, and total oil recovery by 2040 is 9.6 billion barrels. In this scenario, however, production would be lower after 2026 than in the most likely case; in essence faster drilling recovers the oil sooner but makes future supply more problematic.

3. FASTEST RATE scenario: Peak production occurs in 2018 at 2.03 MMbbl/d. Drilling continues until 2022, and total oil recovery by 2040 is 9.9 billion barrels. In this scenario, however, production would be lower after 2025 than in the most likely case; in essence faster drilling recovers the oil sooner but makes future supply more problematic.

[82] Data from Drillinginfo retrieved September 2014.

The following two figures add natural gas, as oil equivalent energy, and differentiate oil from condensate production for the “Most Likely Rate” scenario (the Texas Railroad Commission reports that approximately 20% of liquids production is condensate,[83] which is generally of lower value than oil).

Figure 2-51 illustrates oil, condensate and gas production for the “Most Likely Rate” scenario in the “Optimistic Case” (100% of the prospective area is drillable at six wells per square mile).

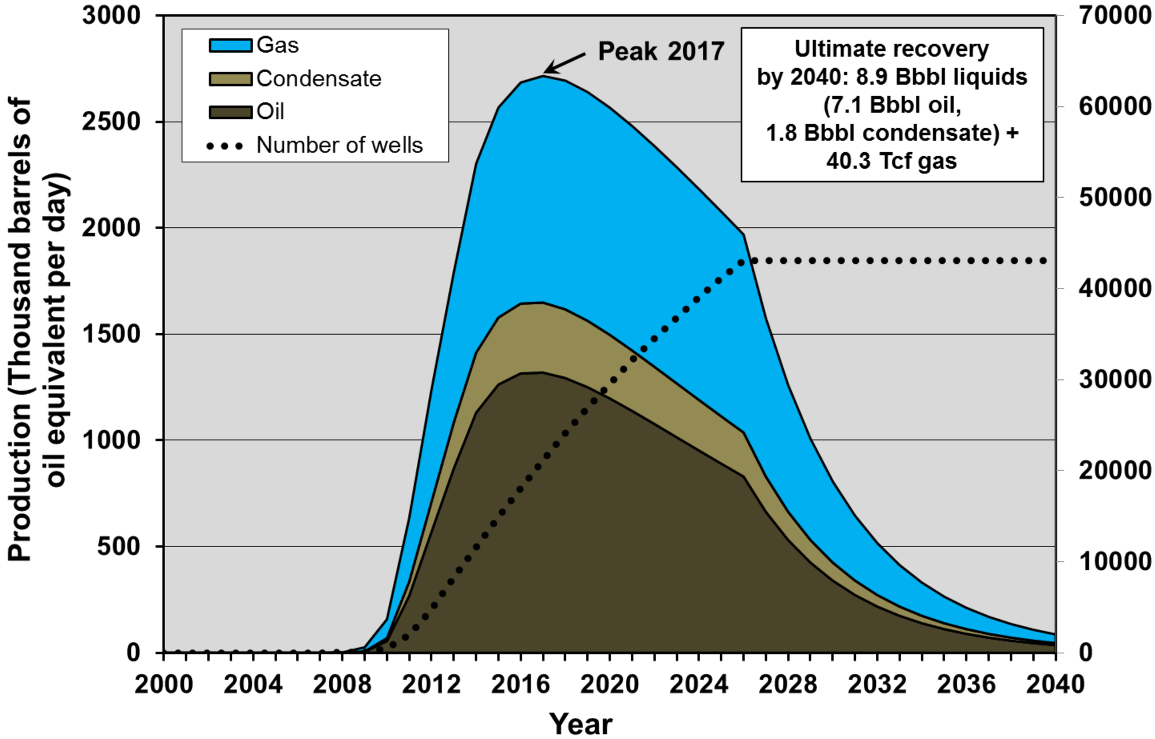


Figure 2-51. “Most Likely Rate” scenario of Eagle Ford production for oil, condensate and gas in the “Optimistic” case (100% of the play area is drillable at six wells per square mile).[84]

In this “Most Likely Rate” scenario, drilling continues at 3,550 wells/year, declining to 2,000 wells/year.

In this case, peak production occurs in 2017 at 2.7 MMbbl/d of oil equivalent. Drilling continues until 2026, total liquids recovery is 8.9 billion barrels (7.1 billion barrels of oil and 1.8 billion barrels of condensate), and total gas recovery is 40.3 trillion cubic feet.

[83] Texas Railroad Commission, “Eagle Ford Shale Information,” July 2014, http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale.
[84] Data from Drillinginfo retrieved September 2014.

Realistic Case

Figure 2-52 illustrates oil, condensate and gas production in the "Most Likely Rate" scenario in the "Realistic Case" (only 80% of the remaining prospective area is drillable, at six wells per square mile).

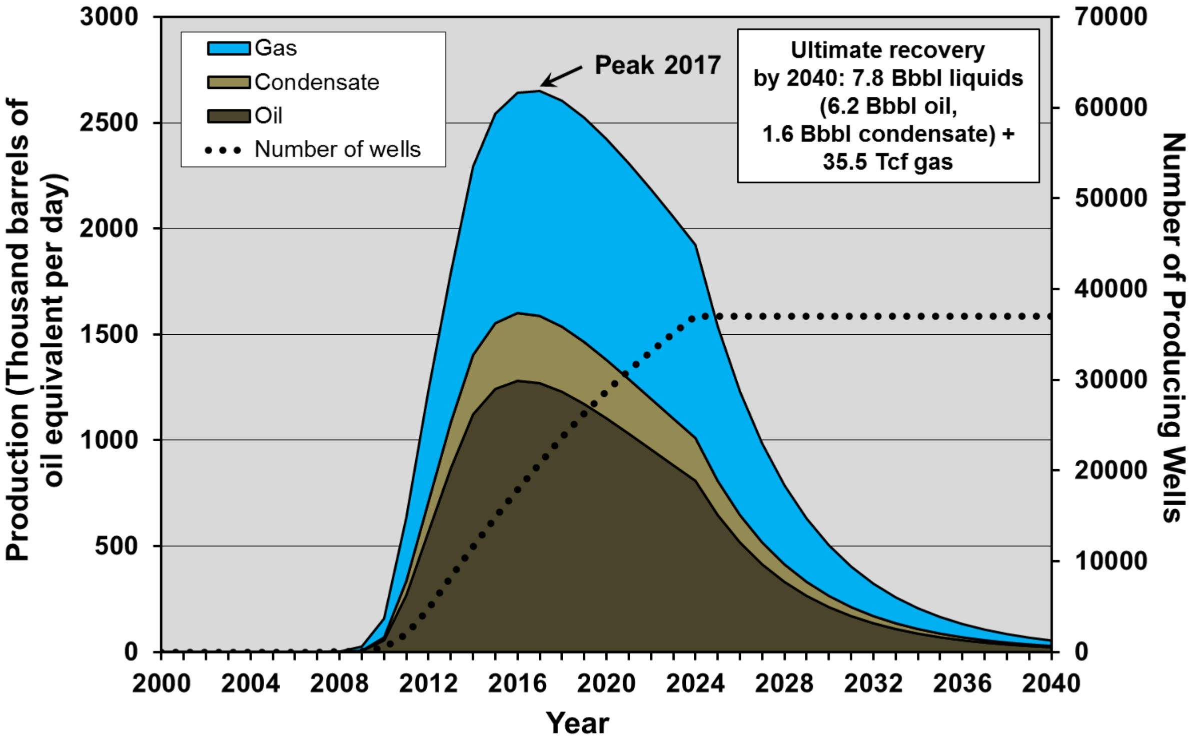


Figure 2-52. "Most Likely Rate" scenario of Eagle Ford production for oil, condensate and gas in the "Realistic Case" (80% of the remaining area is drillable at six wells per square mile).[85]

In this "Most Likely Rate" scenario, drilling continues at 3,550 wells/year, declining to 2,000 wells/year.

In this case, peak production occurs in 2017 at 2.65 MMbbl/d of oil equivalent. Drilling continues until 2024, total liquids recovery by 2040 is 7.8 billion barrels (6.2 billion barrels of oil and 1.6 billion barrels of condensate), and total gas recovery is 35.5 trillion cubic feet.

[85] Data from Drillinginfo retrieved September 2014.

2.3.2.7 Comparison to EIA Forecast

Figure 2-53 compares the EIA's reference case projection for Eagle Ford tight oil production to the "Most Likely Rate" scenario of the "Realistic" Case presented above.

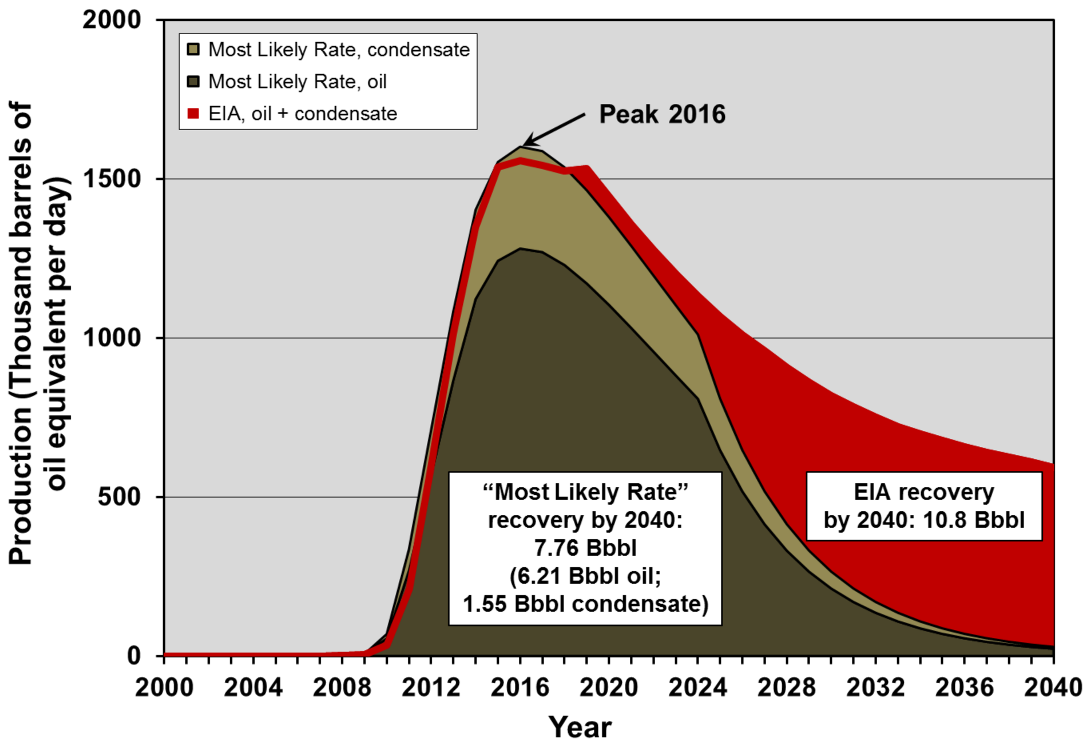


Figure 2-53. "Most Likely Rate" scenario ("Realistic" case) of Eagle Ford tight oil production compared to the EIA reference case, 2000 to 2040.[86]

This "Most Likely Rate" scenario sees 3,550 wells/year, declining to 2,000 wells/year. By 2040, 7.76 billion barrels of liquids would be recovered: 6.21 Bbbls of oil and 1.55 Bbbls of condensate.

This comparison reveals:

- The EIA's forecast of the timing of peak production (2016) in the Eagle Ford is the same as the projection of this report.
- The EIA's forecast of the production rate at peak (1.56 million bpd) is lower than the projection of this report (1.60 million bpd), but only slightly.
- The EIA projects a higher tail of production after peak, with estimated ultimate recovery (EUR) of 10.8 billion barrels by 2040 (10.2 billion for 2014-2040) as opposed this report's projection of 7.8 billion barrels by 2040 (7 billion for 2014-2040).

In short, the EIA is forecasting 3.2 billion additional barrels of future Eagle Ford production than this report finds substantiated. The EIA's assumption that production will be nearly 600,000 barrels per day in 2040 implies that much additional oil will be recovered.

[86] EIA, *Annual Energy Outlook 2014*.

2.3.2.8 Eagle Ford Play Analysis Summary

As with the Bakken, several things are clear from this analysis:

1. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Approximately 2,285 wells must be drilled each year to keep production flat at current levels.

2. The production profile is most dependent on drilling rate and to a lesser extent on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Drilling rate is determined by capital input, which currently is about $28 billion per year to drill 3,550 wells, not including leasing and other ancillary costs.

3. Peak production is highly likely to occur in the 2016 to 2018 timeframe and will occur at between 1.6 and 2.0 MMbbl/d. The most likely peak is about 1.6 MMbbl/d in 2016.

4. Increased drilling rates would raise the level of peak production and move it forward a few months but would not appreciably increase cumulative oil recovery through 2040. Increased drilling rates effectively recover the oil sooner making the supply situation worse later.

5. The projected recovery of 7.8 billion barrels by 2040 in the "Most Likely Rate" scenario of the "Realistic" case (i.e., six wells per square mile "risked" at 80%) is considerably less than the 10.8 billion barrels forecast by the EIA to be recovered by 2040.[87]

6. These projections are optimistic in that they assume the capital will be available for the drilling "treadmill" that must be maintained (roughly $210 billion is needed to drill more than 26,200 wells excluding leasing and ancillary costs). This is not a sure thing as drilling in the poorer-quality parts of the play will require much higher oil prices to be economic. Failure to maintain drilling rates will result in a steeper drop off in production.

7. Nearly four times the current number of wells will be required to recover 7.8 billion barrels by 2040 in the "Realistic" case assuming six wells per square mile "risked" at 80%.

8. The concept that the Eagle Ford will maintain a production plateau beyond its peak is unwarranted, even with extremely large capital inputs.

[87] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

2.4 THE PERMIAN BASIN PLAYS

The Permian Basin is the third largest source of tight oil production growth in the U.S. after the Bakken and Eagle Ford. The Permian Basin has been a prolific conventional oil and gas producer for nearly 100 years. Some 400,000 wells have been drilled there, producing more than 30 billion barrels of oil and 108 trillion cubic feet of gas.

Figure 2-54 illustrates the distribution of wells drilled since 1970 in the basin in Texas and southeastern New Mexico. The basin contains five major plays and several smaller ones that have collectively allowed oil production to grow by more than 500,000 barrels per day since 2005.[88] Three of these, the Spraberry, Wolfcamp, and Avalon/Bone Spring, are projected by the EIA to be major contributors to future production (see Figure 2-5).

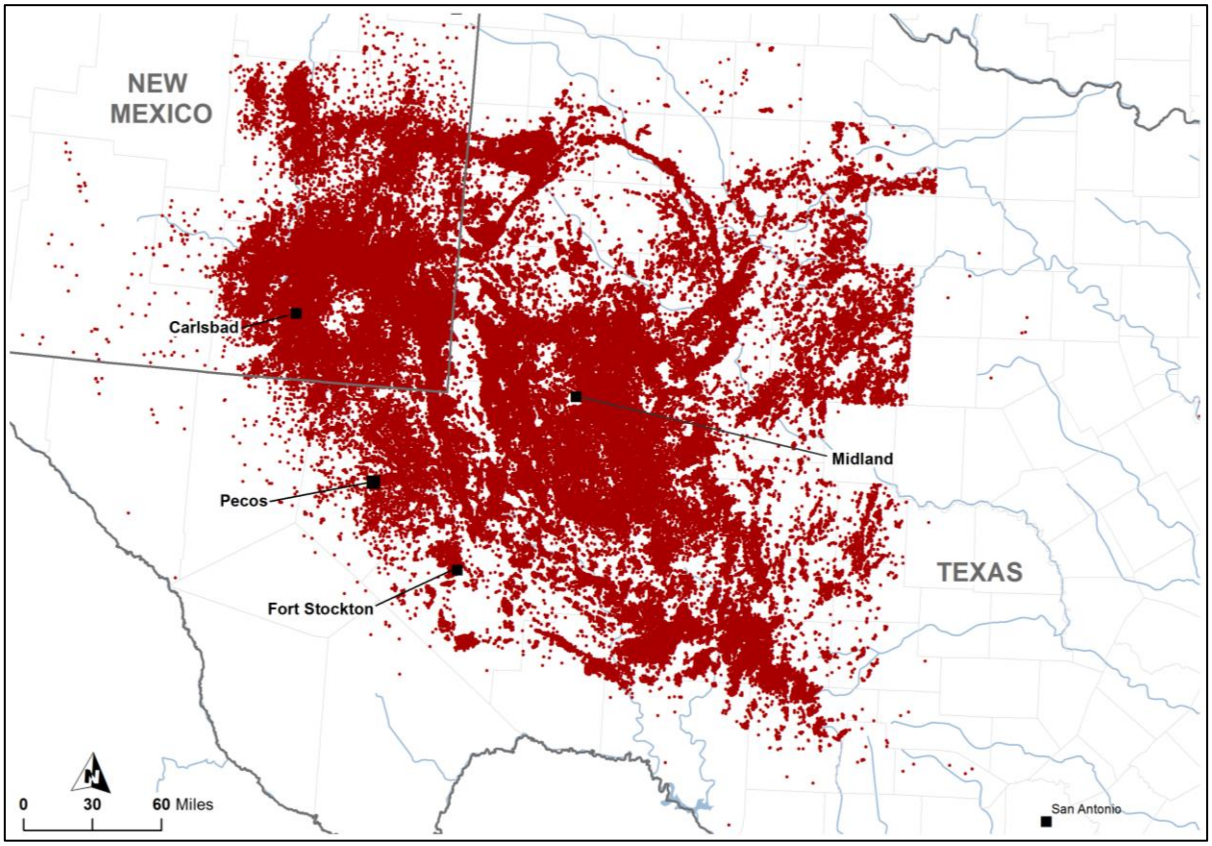


Figure 2-54. Distribution of wells drilled since 1970 in the Permian Basin of Texas and southeastern New Mexico.[89]

[88] EIA, "Six formations are responsible for surge in Permian Basin crude oil production," *Today in Energy*, July 9, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=17031.
[89] Data from Drillinginfo retrieved July 2014.

Production of oil and gas from the Permian Basin peaked in 1973 but has undergone a renaissance since 2010, with the application of new technology to old reservoirs. Figure 2-55 illustrates oil and gas production in the basin since 1960.

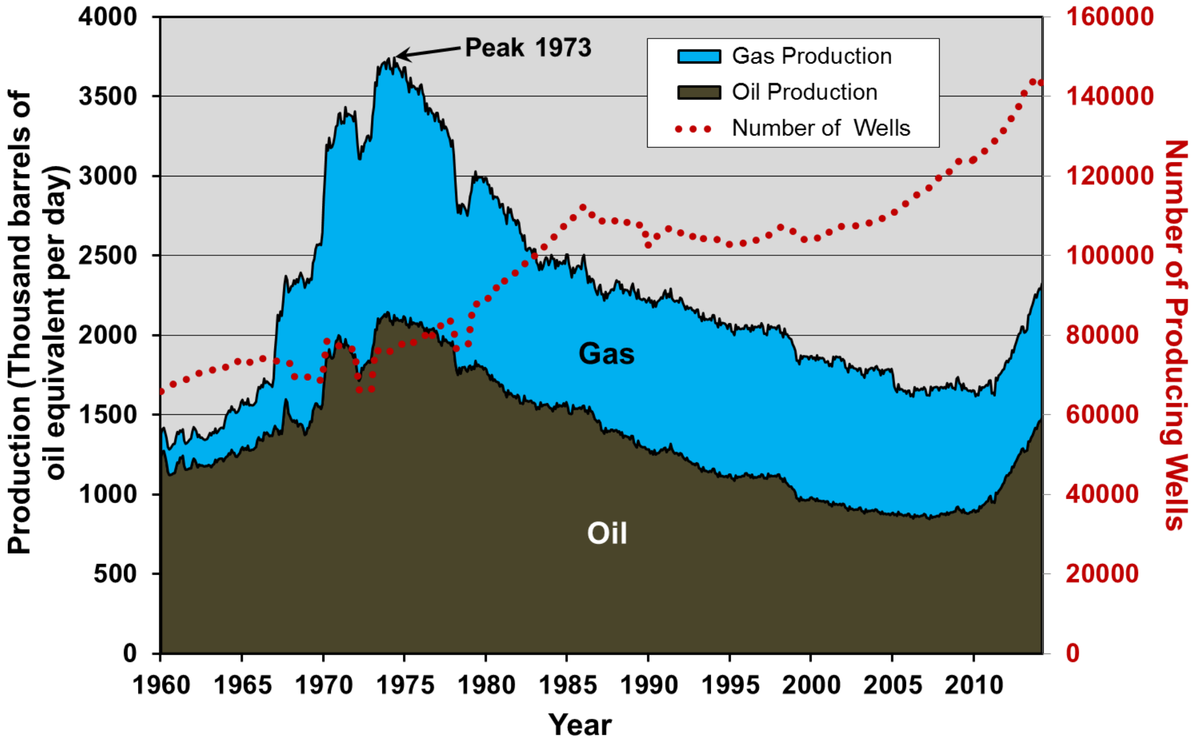


Figure 2-55. Permian Basin oil and gas production and number of producing wells, 1960 to 2014.[90]

Gas production is expressed as "barrels of oil equivalent" (6,000 cubic feet of gas is approximately equivalent to one barrel of oil on an energy basis).

[90] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

Unlike the Bakken and Eagle Ford shale plays, tight oil production in the Permian Basin is from both horizontal and vertical fracked wells. Coupled with the fact that the Permian Basin has been producing for nearly a century, this makes it difficult to separate truly new “tight oil” production from conventional production. Figure 2-56 illustrates production from vertical and horizontal wells in the Permian Basin. Production growth has occurred from both well types, although horizontal wells appear to contribute a larger proportion of the growth.

As mentioned above, the three plays that the EIA is counting on to meet a significant proportion of its tight oil forecasts from the Permian Basin are the Spraberry, Wolfcamp, and Avalon/Bone Spring. These plays are reviewed below with respect to production characteristics and future growth potential in the light of the EIA projections for them.

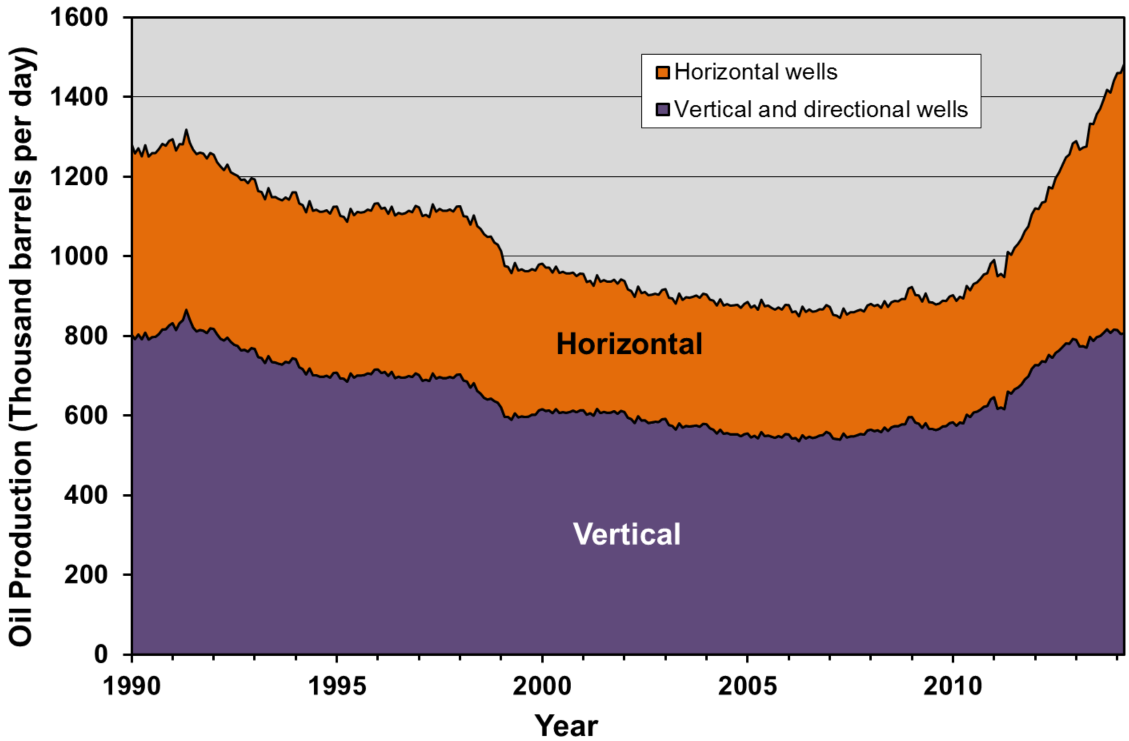


Figure 2-56. Oil production by well type in the Permian Basin, 1990 to 2014.[91]

Recent production growth is a function of both horizontal and vertical wells.

[91] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.4.1 Spraberry Play

The EIA forecasts recovery of 6.5 billion barrels of oil from the Spraberry play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Spraberry play has been producing oil and gas for decades. Nearly 37,000 wells have been drilled of which more than 25,000 are currently producing. The play has produced over 1.8 billion barrels of oil and more than 4.2 trillion cubic feet of natural gas over its lifetime. Production comes from the Spraberry reservoir proper, and an equivalent reservoir termed “Trend Area”, which together make up the Spraberry play. Figure 2-57 illustrates well distribution within the play.

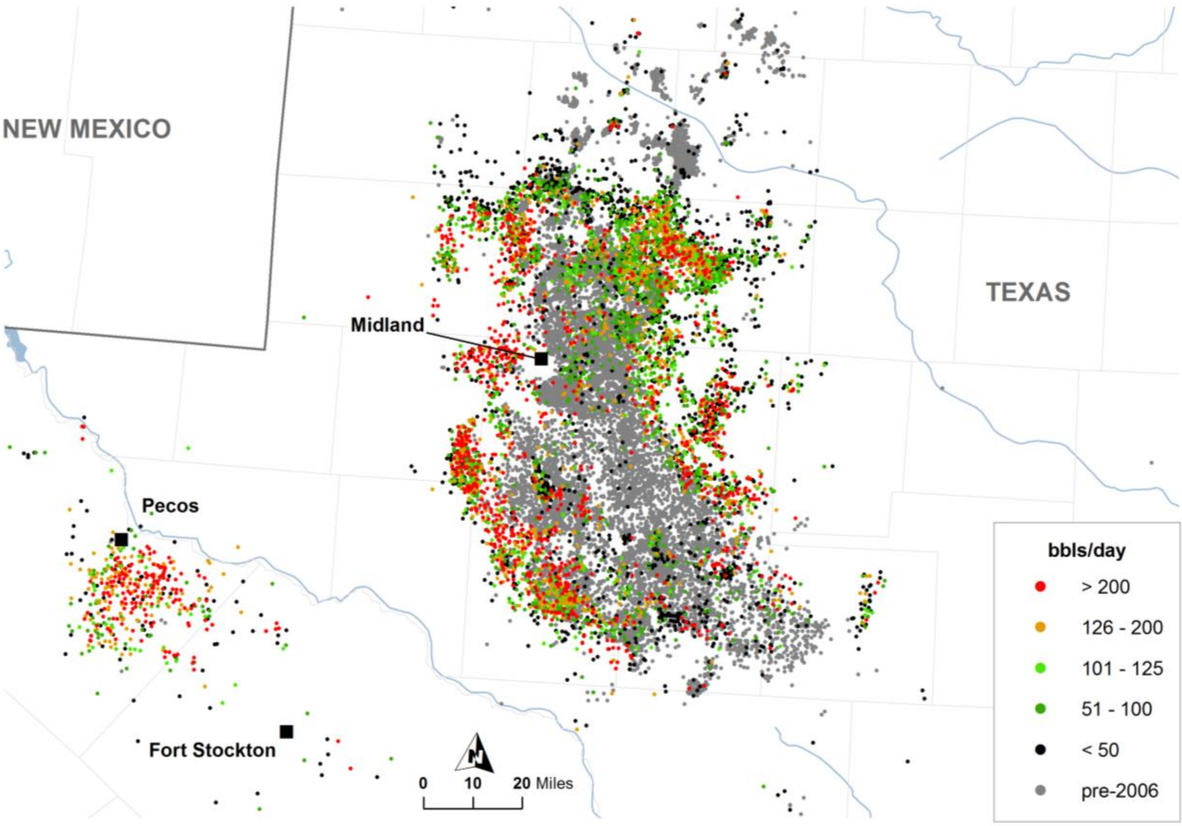


Figure 2-57. Distribution of wells in the Spraberry play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[92]

Only wells drilled in 2006 and later are considered as possible “tight oil” production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[92] Data from Drillinginfo retrieved July 2014.

2.4.1.1 Production History

Production of oil in the Spraberry has more than tripled since 2005 and including natural gas (on an energy equivalent basis) is up four-fold as illustrated in Figure 2-58. The number of producing wells has also more than doubled over this period.

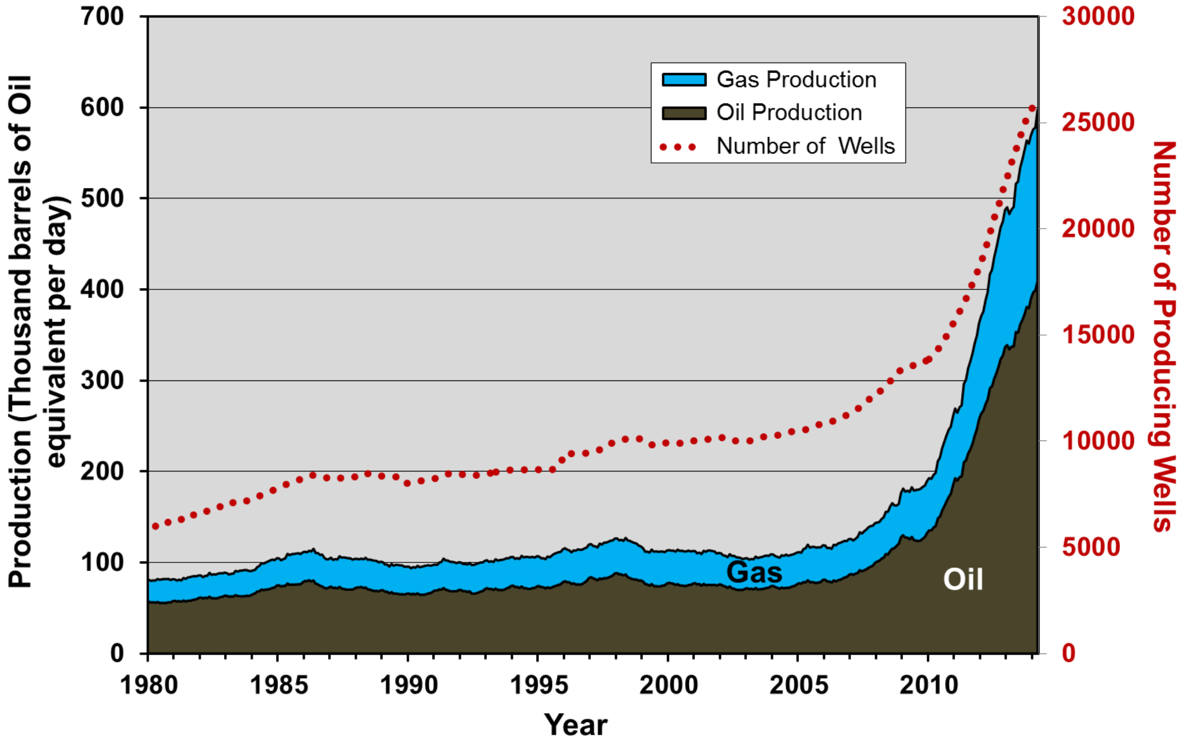


Figure 2-58. Spraberry play oil and gas production and number of producing wells, 1980 to 2014.[93]

Producing well count is now above 25,000.

[93] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

A look at the split in production by well type reveals that much of this growth is attributable to vertical wells, although horizontal wells are becoming increasingly important (Figure 2-59). New completion technology in both well types is obviously paying dividends.

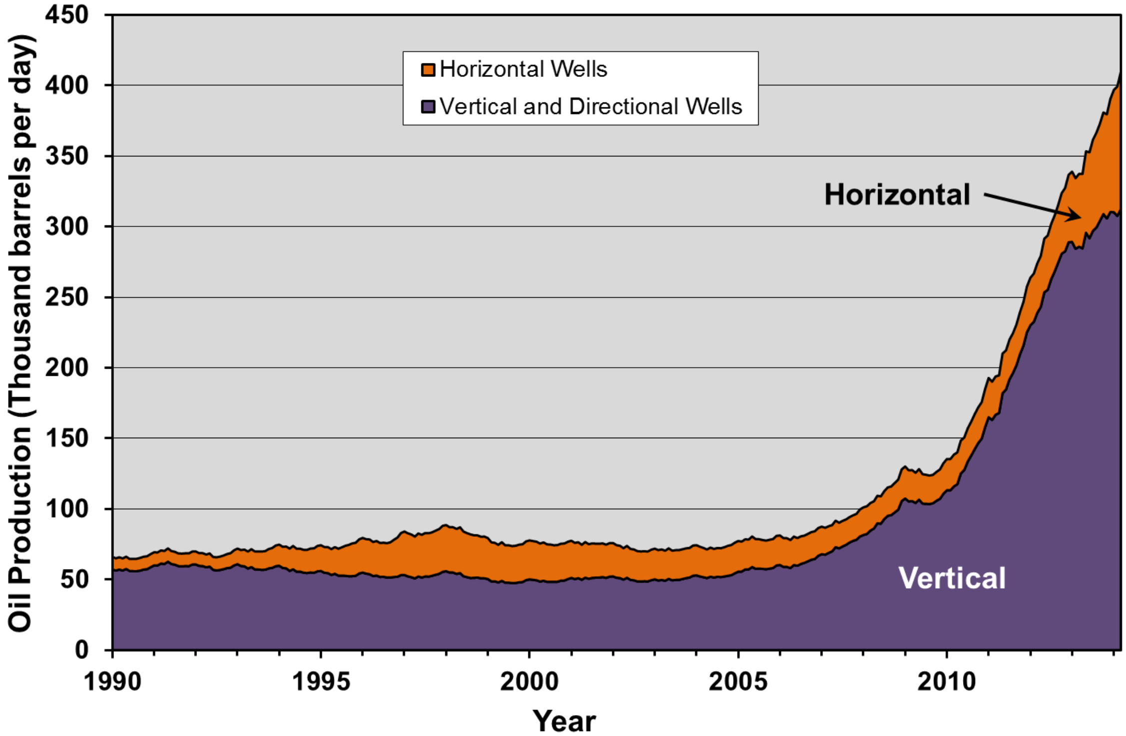


Figure 2-59. Oil production from the Spraberry play by well type.[94]

Although vertical wells have accounted for much of the recent production growth, horizontal wells now appear to be the most important contributors.

[94] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.4.1.2 Well Quality

A look at well quality reveals that the Spraberry is unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-60 illustrates the average well decline profile for all wells; Figure 2-61 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are just a tenth of the initial production of an average Bakken well in a top county. Horizontal wells are more than double the initial productivity of the average well but still pale by comparison to a Bakken or Eagle Ford well. The average three-year decline of Spraberry wells is, however, somewhat lower than the Bakken at 60% and 72% for all wells and horizontal wells, respectively.

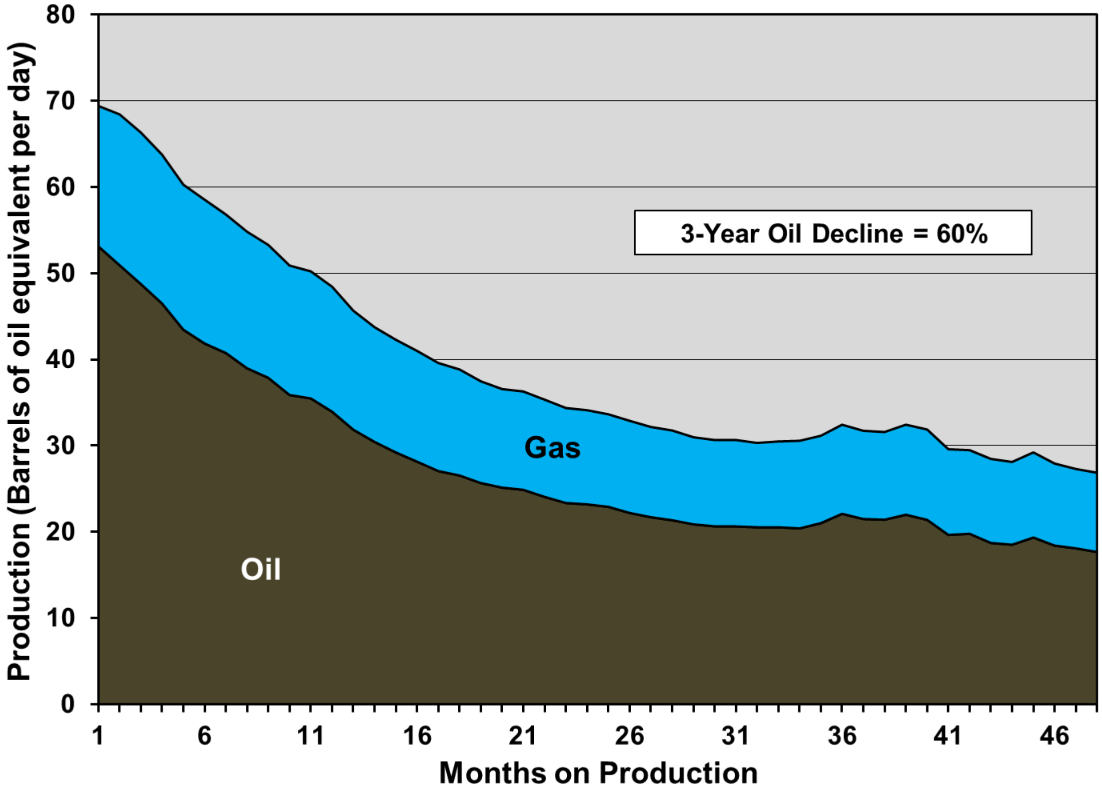


Figure 2-60. Oil and gas average well decline profile for all wells in the Spraberry play.[95]

On an energy equivalent basis these wells have an initial productivity of less than a tenth that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[95] Data from Drillinginfo retrieved July 2014.

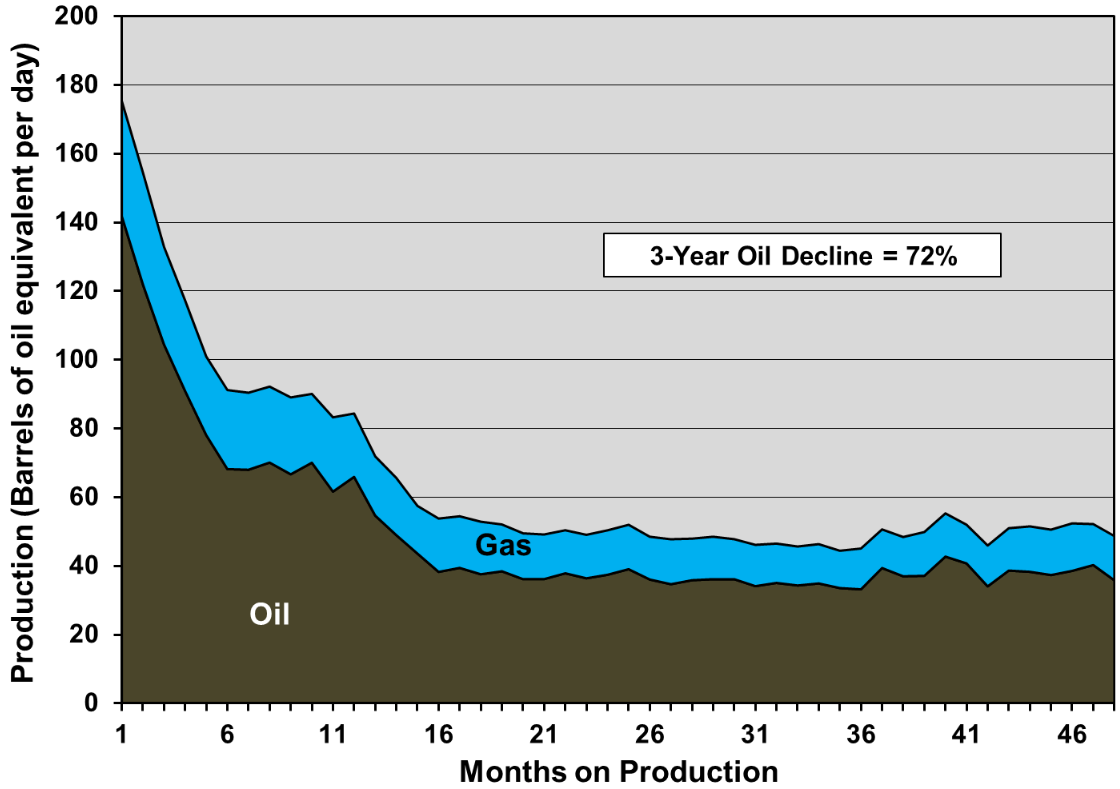


Figure 2-61. Oil and gas average well decline profile for horizontal wells in the Spraberry play.[96]

On an energy equivalent basis these wells have an initial productivity of less than a third that of the average well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[96] Data from Drillinginfo retrieved July 2014.

2.4.1.3 EIA Forecast

The EIA's projection for Spraberry play production through 2040 in its reference case is illustrated in Figure 2-62. Total recovery between 2012 and 2040 is forecast to be 6.5 billion barrels; this amounts to 15% of the EIA's reference case forecast for U.S. tight oil production through 2040. Cumulative production by 2040 amounts to 80% of the "unproved technically recoverable resources" the EIA estimated for the Spraberry as of January 1, 2012.

Given that this is a redevelopment of an old play which is already extensively drilled, the fact that the wells are of relatively low quality, and the nature of likely production profiles from shale plays like the Bakken, this would seem to be a highly optimistic forecast. It is already overestimating actual production by 55% in year one, as actual production for 2013 amounted to 390,000 barrels per day compared to an estimate of 604,000 barrels by the EIA. Furthermore, the EIA is projecting that production will be 505,000 barrels per day in 2040, which is 30% above current levels. High field decline rates make it very likely that production decline after its projected peak in 2021 will be much steeper than projected. Given what is known, this EIA forecast would seem to have a very high optimist bias.

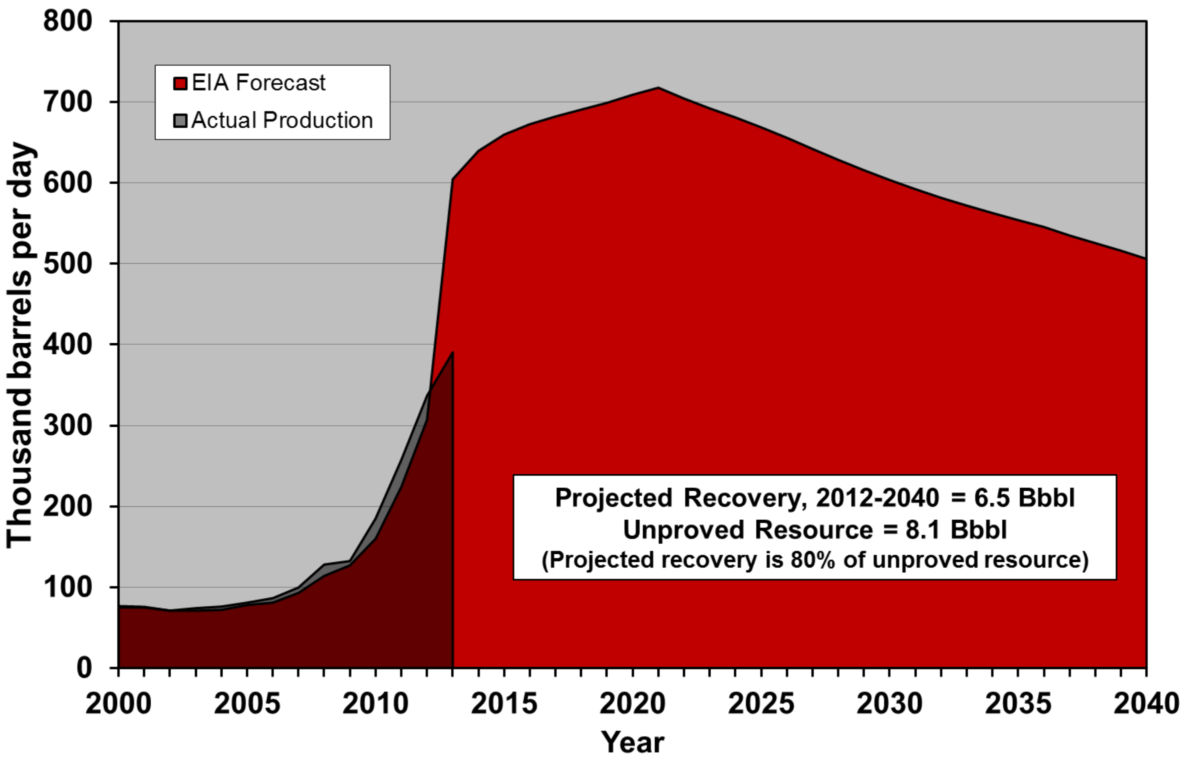


Figure 2-62. EIA reference case projection of oil production from the Spraberry play through 2040, with actual production to 2013.[97]

The forecast total recovery of 6.5 billion barrels over the 2012-2040 period amounts to 80% of the 8.1 billion barrels of "unproved technically recoverable resources as of January 1, 2012".[98]

[97] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[98] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.4.2 Wolfcamp Play

The EIA forecasts recovery of 2.64 billion barrels of oil from the Wolfcamp play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Wolfcamp play has also been producing oil and gas for decades. Over 12,800 wells have been drilled of which more than 6,000 are currently producing. The play has produced over 870 million barrels of oil and nearly 4.8 trillion cubic feet of natural gas over its lifetime. Figure 2-63 illustrates well distribution within the Wolfcamp play.

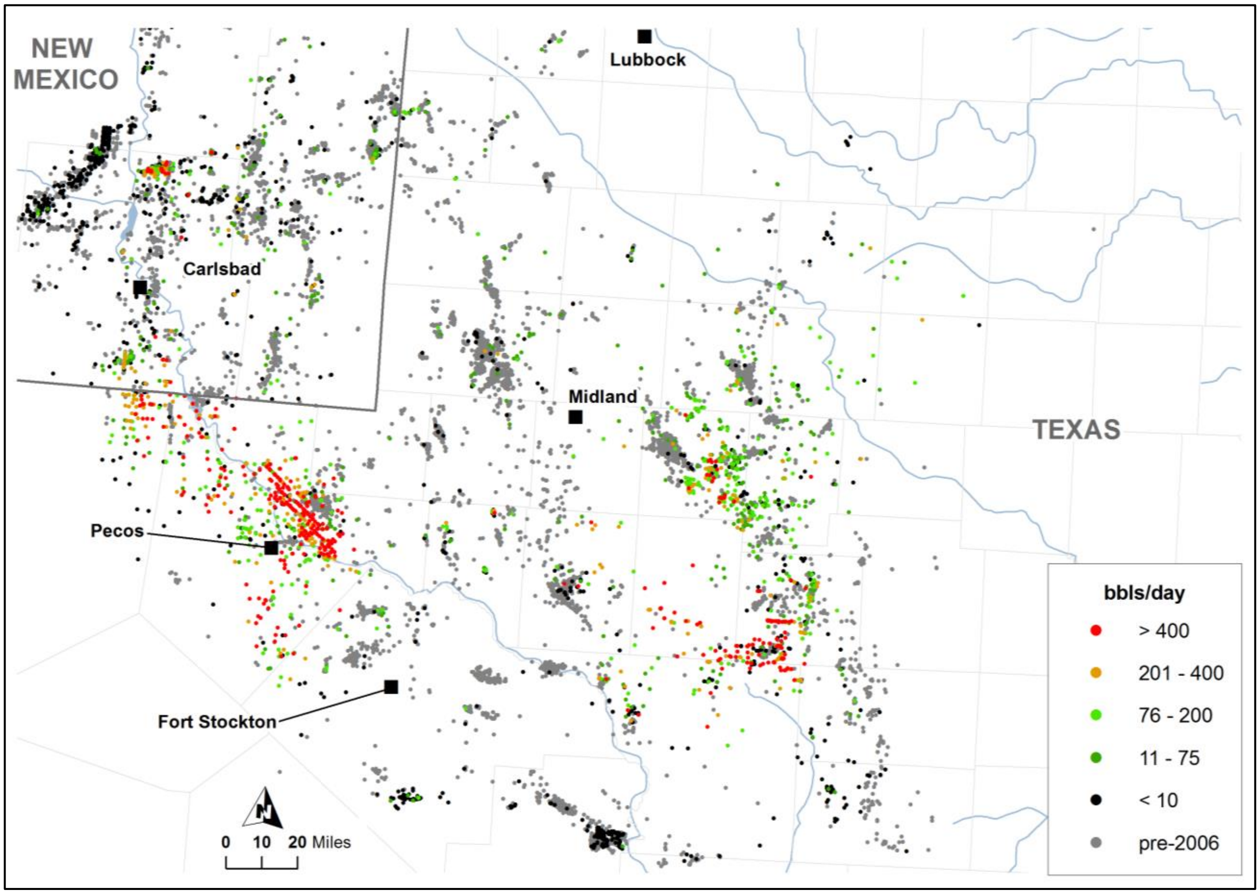


Figure 2-63. Distribution of wells in the Wolfcamp play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[99]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[99] Data from Drillinginfo retrieved July 2014.

2.4.2.1 Production History

Production of oil in the Wolfcamp has quadrupled since 2005, and including natural gas (on an energy equivalent basis) is up three-fold as illustrated in Figure 2-64.

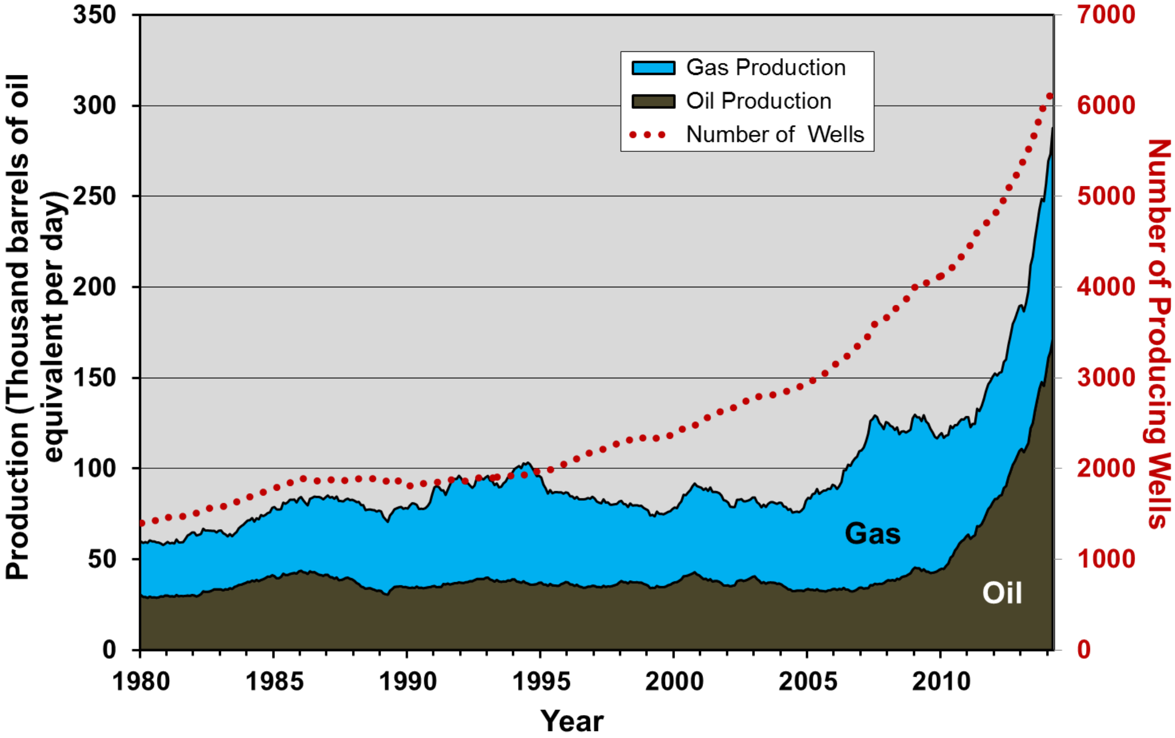


Figure 2-64. Wolfcamp play oil and gas production and number of producing wells, 1980 to 2014.[100]

Producing well count is now over 6,000.

[100] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

The number of producing wells has also doubled over this period. A look at the split in production by well type reveals that virtually all of this growth is attributable to horizontal wells (Figure 2-65). Horizontal fracking technology is obviously paying dividends.

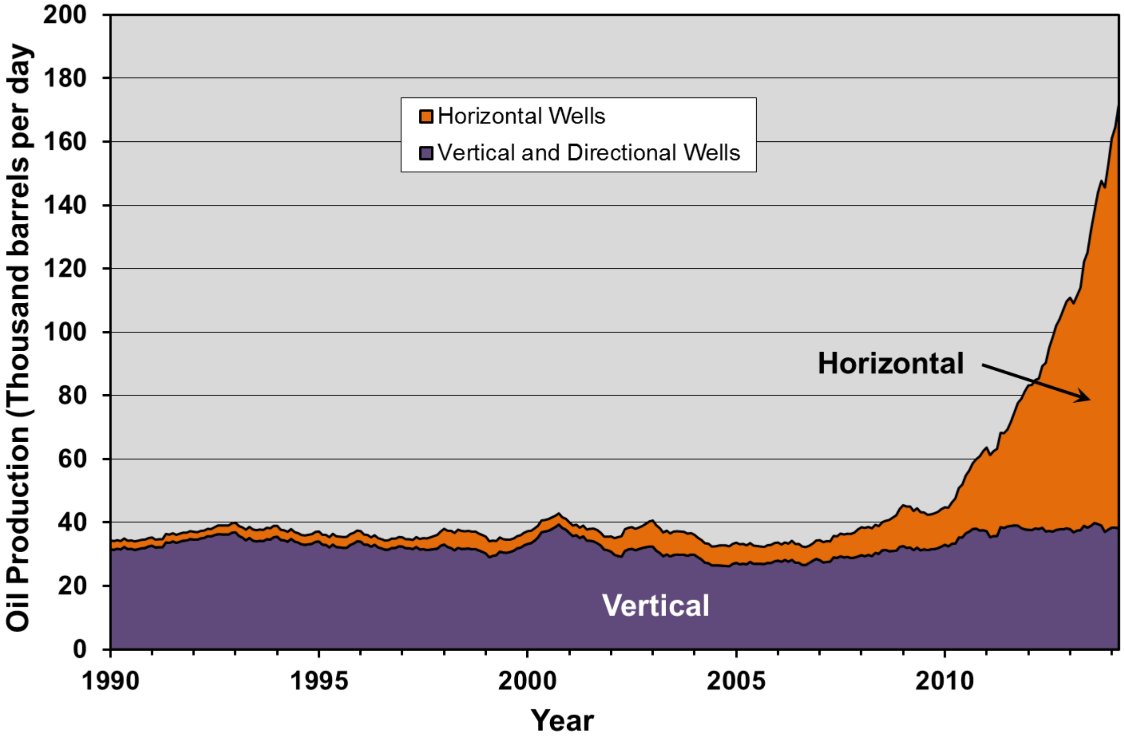


Figure 2-65. Oil production from the Wolfcamp play by well type.[101]

Horizontal wells are now accounting for most of the production growth.

[101] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.4.2.2 Well Quality

A look at well quality reveals that the Wolfcamp, although considerably better than the Spraberry, is unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-66 illustrates the average well decline profile for all wells; Figure 2-67 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are just a quarter of the initial production of an average Bakken well in a top county. Horizontal wells are nearly double the initial productivity of the average well but still pale by comparison to a Bakken or Eagle Ford well. The average three-year decline of Wolfcamp wells is comparable to the Bakken at 81% and 85% for all wells and horizontal wells, respectively.

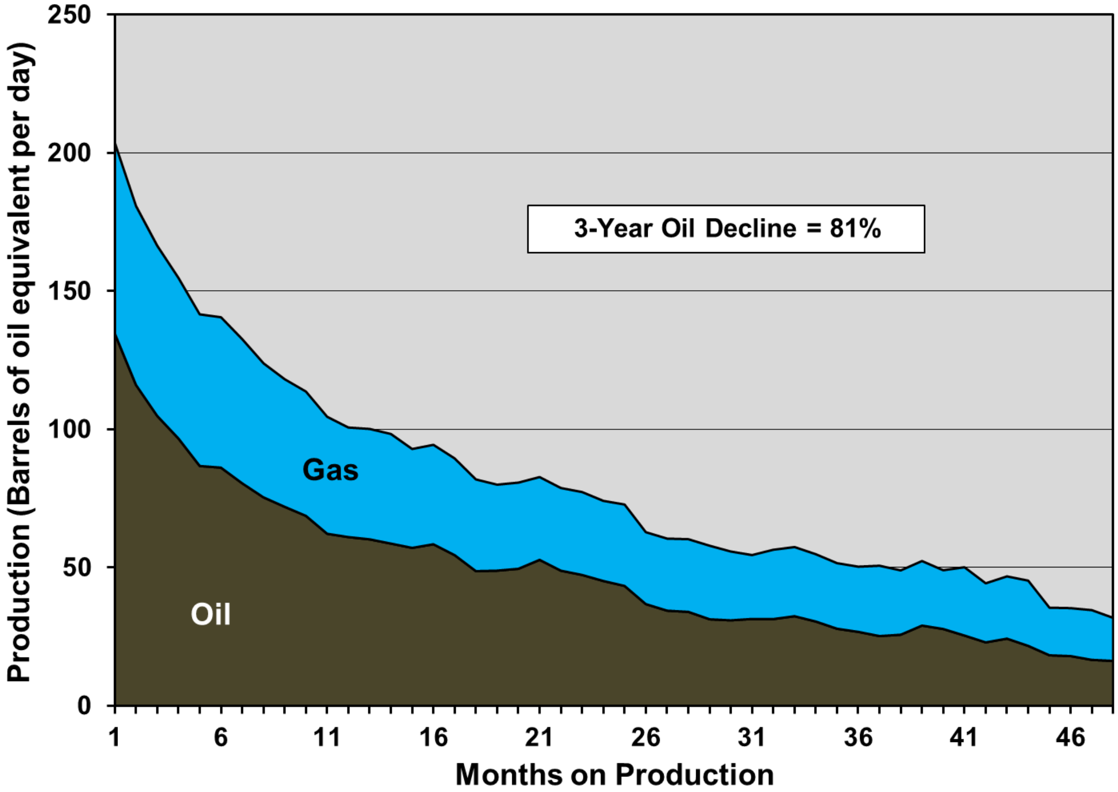


Figure 2-66. Oil and gas average well decline profile for all wells in the Wolfcamp play.[102]

On an energy equivalent basis these wells have an initial productivity of less than a quarter that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[102] Data from Drillinginfo retrieved July 2014.

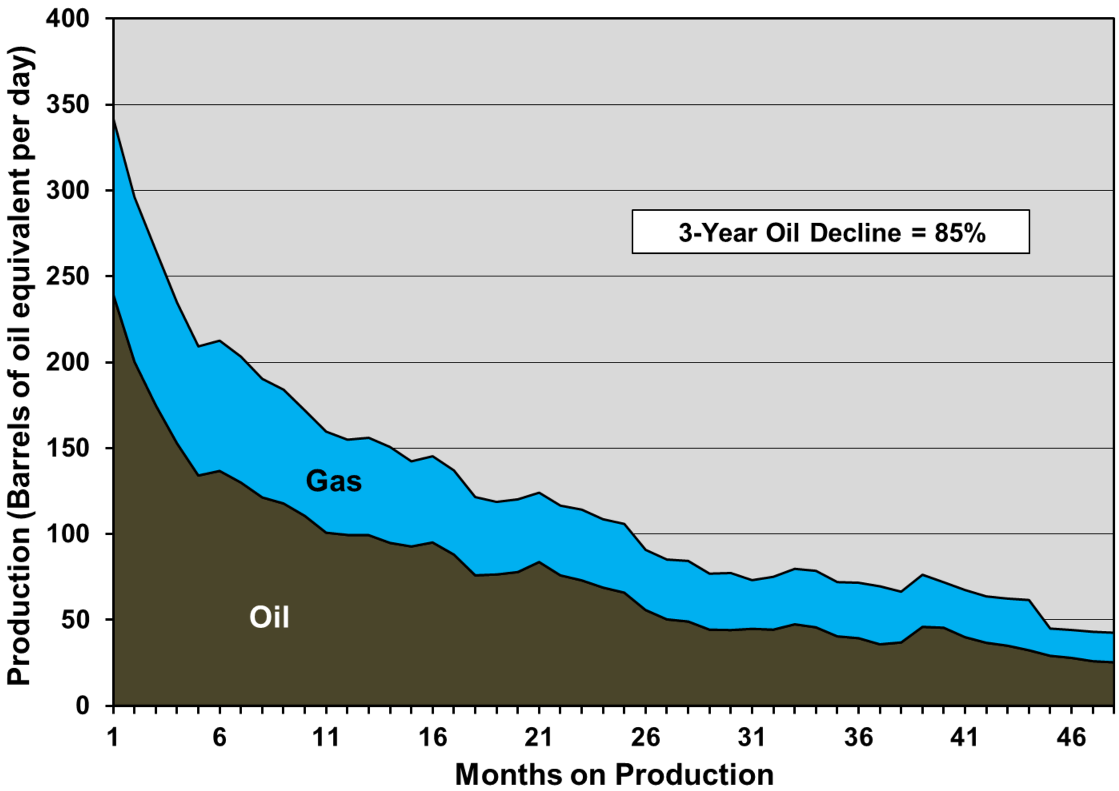


Figure 2-67. Oil and gas average well decline profile for horizontal wells in the Wolfcamp play.[103]

On an energy equivalent basis these wells have an initial productivity of about a third of the average horizontal well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[103] Data from Drillinginfo retrieved July 2014.

2.4.2.3 EIA Forecast

The EIA's projection for Wolfcamp play production through 2040 in its reference case is illustrated in Figure 2-68. Total recovery between 2012 and 2040 is forecast to be 2.64 billion barrels. This amounts to 6.1% of its U.S. reference case tight oil production through 2040. Cumulative production by 2040 amounts to 78% of the "unproved technically recoverable resources" the EIA estimated for the Wolfcamp as at January 1, 2012.

Given that this is a redevelopment of an old play which is already extensively drilled, the fact that the wells are of relatively low quality, and the nature of likely production profiles from shale plays like the Bakken, this would seem to be an optimistic forecast. It is already off by 36% on the high side in year one, as actual production for 2013 amounted to 153,000 barrels per day compared to an estimate of 209,000 barrels by the EIA. Furthermore, the EIA is projecting that production will be 220,000 barrels per day in 2040, which is 44% above current levels. High field decline rates make it likely that production decline after its projected peak in 2019 will be much steeper than forecast. Given what is known, this EIA forecast would seem to have a high optimist bias.

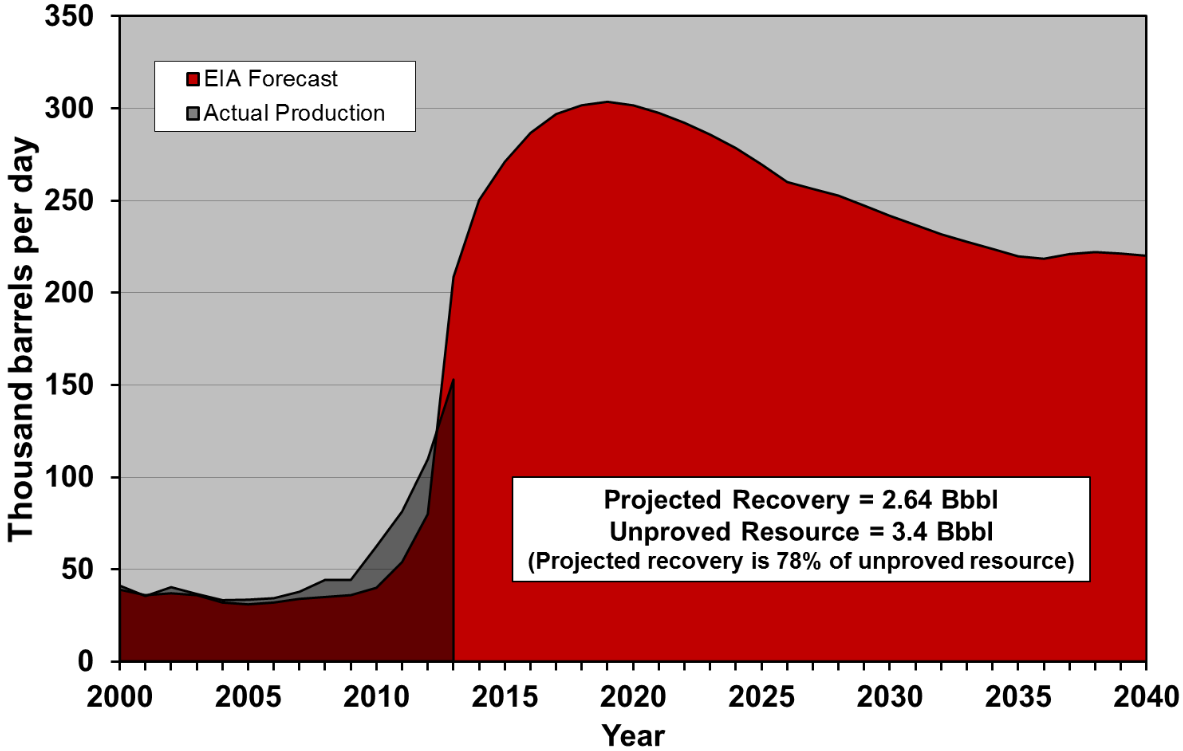


Figure 2-68. EIA reference case projection of oil production from the Wolfcamp play through 2040, with actual production to 2013.[104]

The forecast total recovery of 2.64 billion barrels over the 2012-2040 period amounts to 78% of the 3.4 billion barrels of "unproved technically recoverable resources as of January 1, 2012".[105]

[104] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[105] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.4.3 Bone Spring Play

The EIA forecasts recovery of 0.68 billion barrels of oil from the Bone Spring play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is reasonable and may be on the low end of future production.

The Bone Spring play has, like the Spraberry and Wolfcamp, been producing oil and gas for decades. Over 5,200 wells have been drilled of which 2,500 are currently producing. The play has produced 208 million barrels of oil and 730 billion cubic feet of natural gas over its lifetime. Figure 2-69 illustrates well distribution within the Bone Spring play.

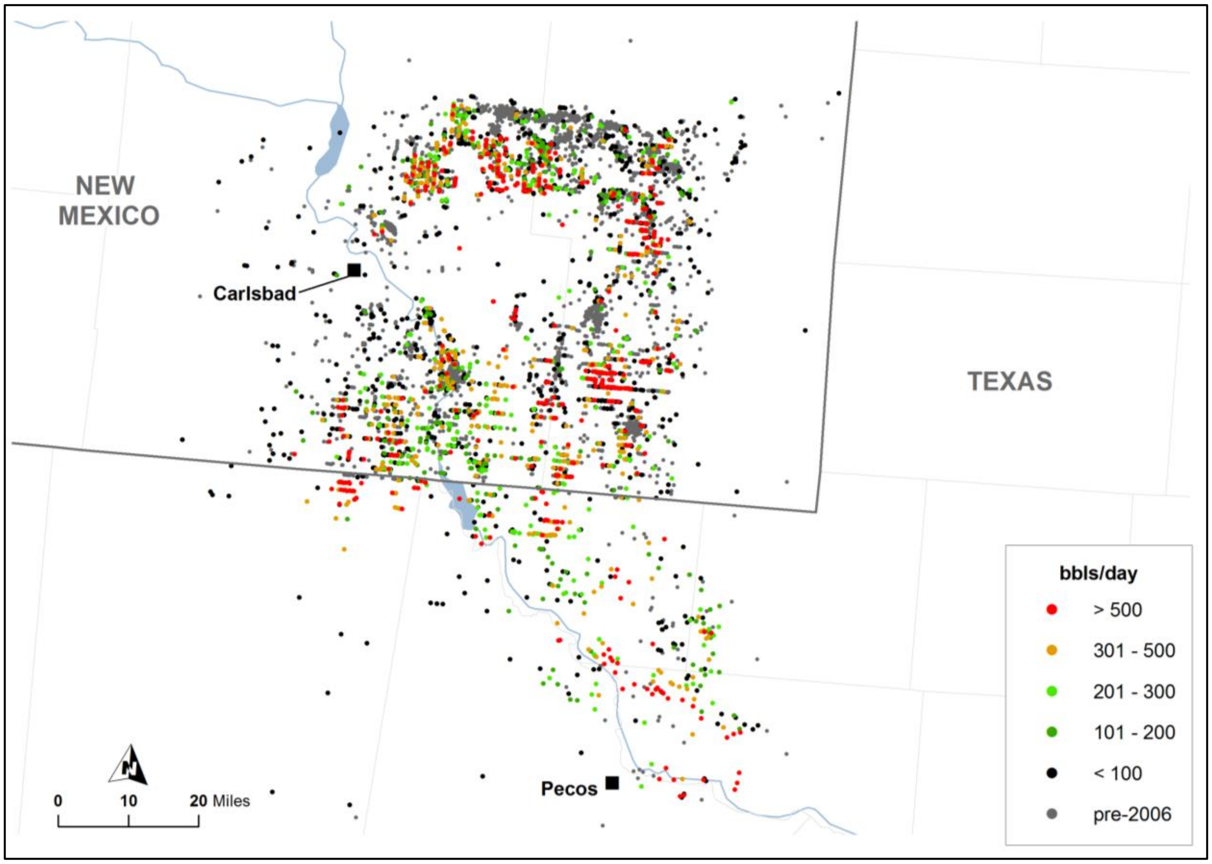


Figure 2-69. Distribution of wells in the Bone Spring play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[106]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[106] Data from Drillinginfo retrieved July 2014.

2.4.3.1 Production History

Production of oil in the Bone Spring has increased more than 10 fold since 2005 and on an energy equivalent basis, including natural gas, is up more than 15-fold as illustrated in Figure 2-70.

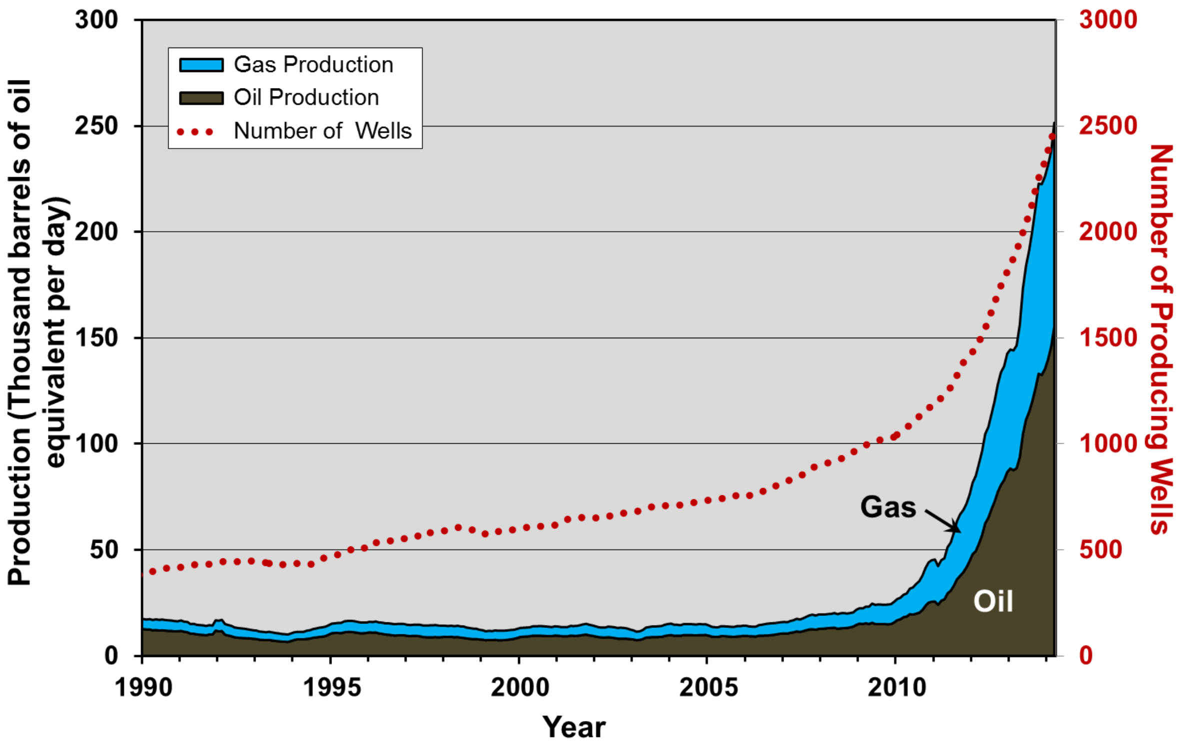


Figure 2-70. Bone Spring play oil and gas production and number of producing wells, 1990 to 2014.[107]

Producing well count is now about 2,500.

[107] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

The number of producing wells has also more than tripled over this period. A look at the split in production by well type reveals that virtually all of this growth is attributable to horizontal wells (Figure 2-71). Horizontal fracking technology is obviously paying dividends.

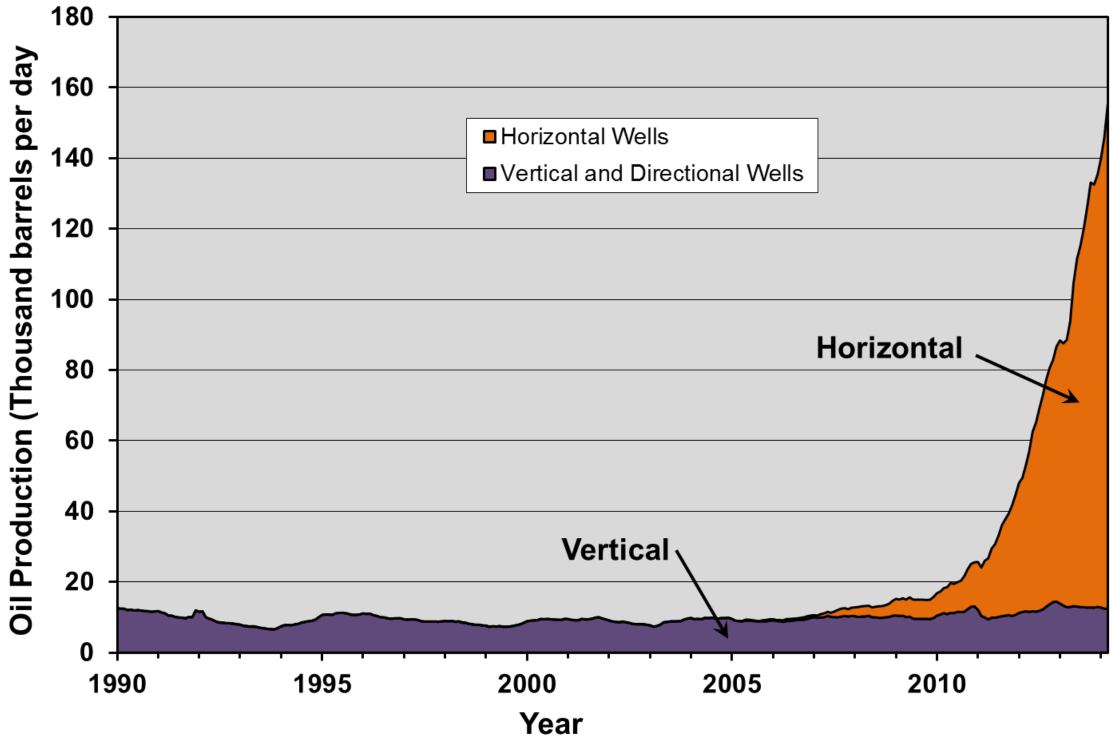


Figure 2-71. Oil production from the Bone Spring play by well type.[108]
Horizontal wells are now accounting for most of the production growth.

[108] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.4.3.2 Well Quality

A look at well quality reveals that the Bone Spring, although considerably better than either the Spraberry or Wolfcamp, is still unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-72 illustrates the average well decline profile for all wells; Figure 2-73 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are about half of the initial production of an average Bakken well in a top county. Horizontal wells are slightly better; the average initial productivity is about two-thirds of an average Bakken well. The average three-year decline of Bone Spring wells is greater that the Bakken at 91% for all wells and for horizontal wells, and is the steepest observed for any shale play.

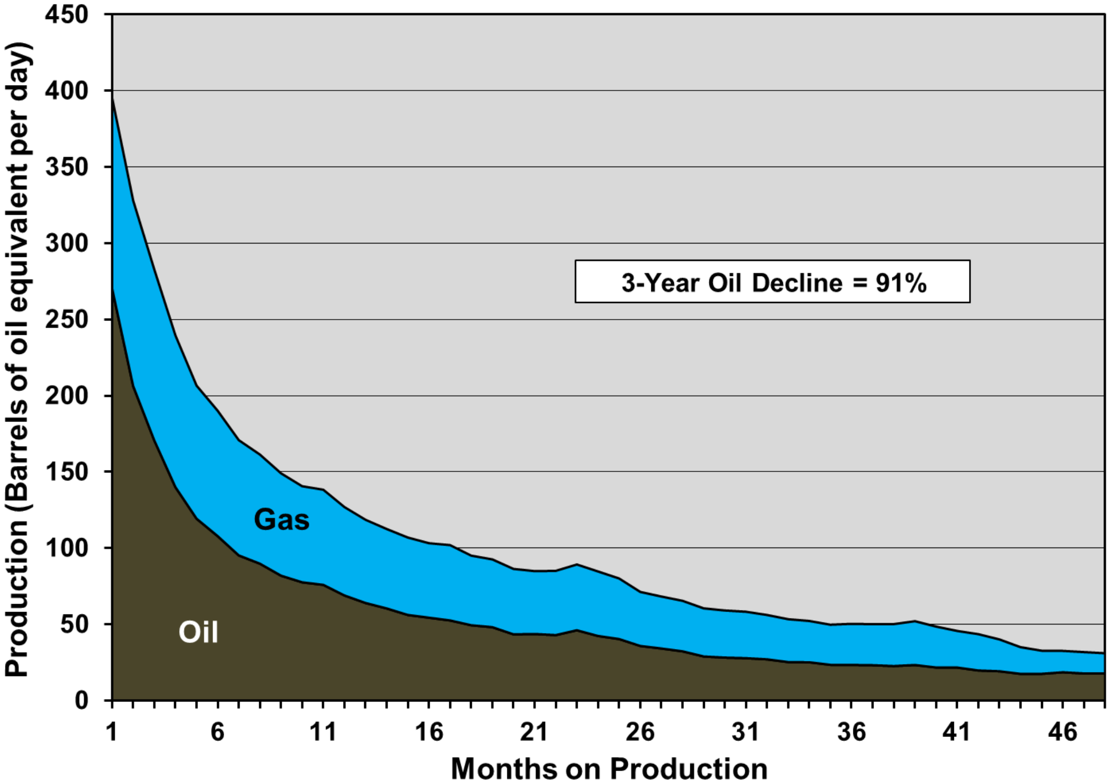


Figure 2-72. Oil and gas average well decline profile for all wells in the Bone Spring play.[109]

On an energy equivalent basis these wells have an initial productivity of about half that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[109] Data from Drillinginfo retrieved July 2014.

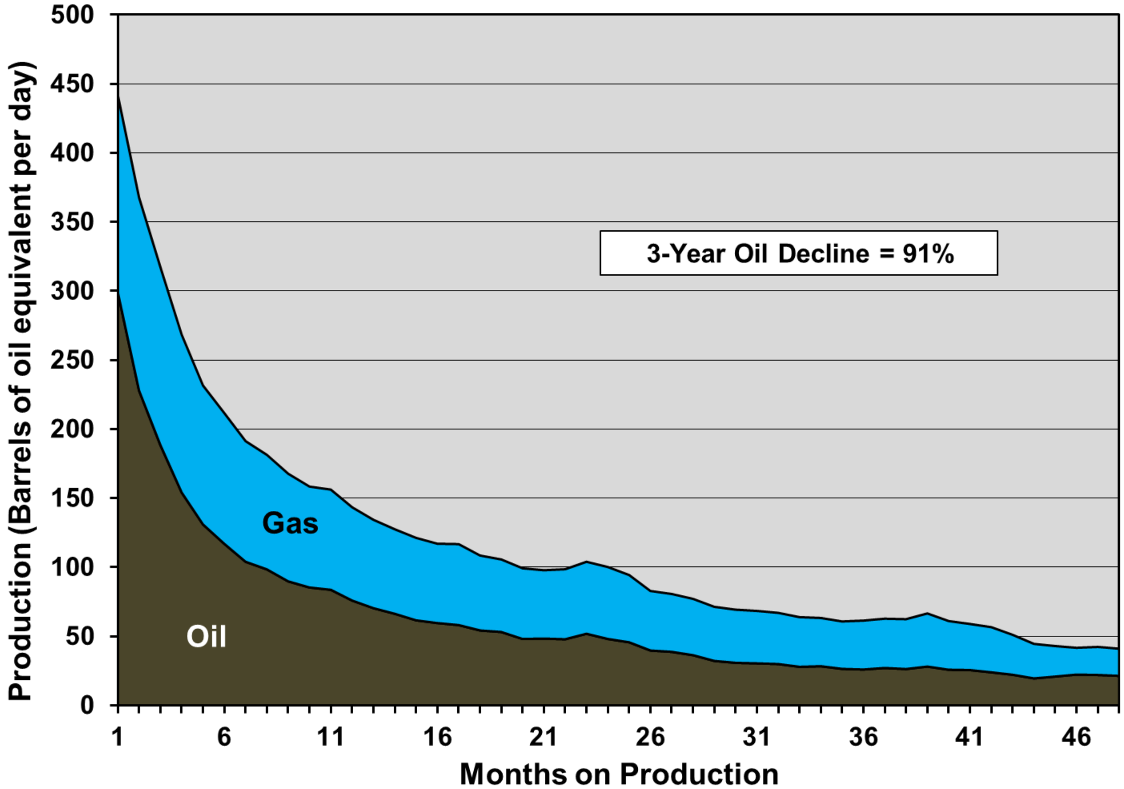


Figure 2-73. Oil and gas average well decline profile for horizontal wells in the Bone Spring play.[110]

On an energy equivalent basis these wells have an initial productivity of about half of the average horizontal well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[110] Data from Drillinginfo retrieved July 2014.

2.4.3.3 EIA Forecast

The EIA's projection for Bone Spring play production through 2040 in its reference case is illustrated in Figure 64. Total recovery between 2012 and 2040 is forecast to be 0.68 billion barrels. This amounts to just 1.6% of its U.S. reference case tight oil production through 2040. Cumulative production by 2040 amounts to 34% of the "unproved technically recoverable resources" the EIA estimated for the Bone Spring as at January 1, 2012.

In this case the EIA's forecast looks conservative, as production is already considerably higher in year one than projected. One could argue with the long extended tail of production but it appears likely that Bone Spring production may rise considerably higher. The very high well- and field-declines noted, which are considerably higher than the other Permian plays examined above, will likely make decline on the far side of peak production much steeper than depicted in the EIA projection. Given what is known, this EIA forecast would seem to have a low optimist bias.

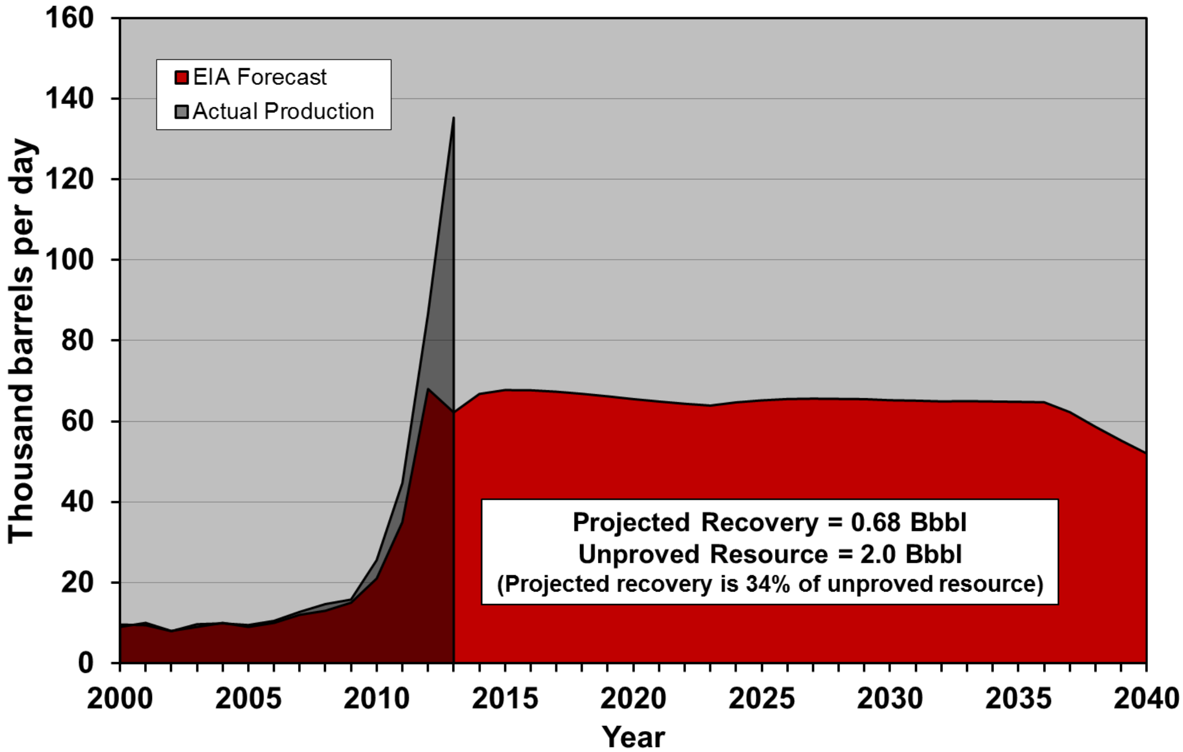


Figure 2-74. EIA reference case projection of oil production from the Bone Spring through 2040, with actual production to 2013.[111]

The forecast total recovery of .68 billion barrels over the 2012-2040 period amounts to 34% of the 2.0 billion barrels of "unproved technically recoverable resources as of January 1, 2012".[112]

[111] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[112] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.4.4 Key Characteristics of the Permian Basin Plays

As mentioned, the Permian Basin is the third largest source of tight oil in the U.S., and the three plays reviewed above constitute 23% of the oil the EIA projects will be recovered by 2040 in its reference tight oil case. In addition to these plays, two smaller Permian plays are listed by the EIA in Figure 2-7 above: the Glorieta-Yeso (actually two separate formations) and the Delaware. These latter two plays display the same characteristics as the first three: they are old plays which have been producing for decades, and although they are increasing somewhat in production, well quality is unremarkable compared to the Bakken and Eagle Ford.

Figure 2-75 illustrates total Permian Basin production, highlighting these five plays which now make up 56% of the total production of the basin.

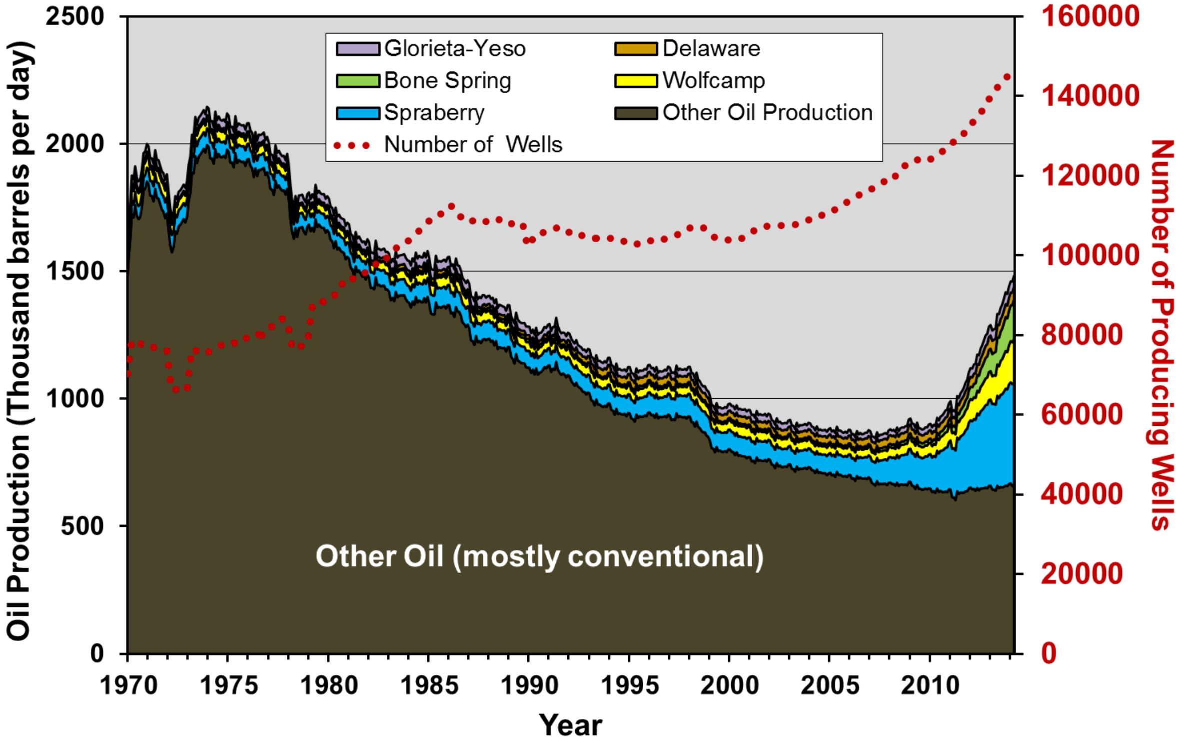


Figure 2-75. Oil production and number of producing wells in the Permian Basin to 2014.[113]

Production from the five tight oil plays the EIA includes in the Permian Basin (see Figure 2-7) is highlighted. As of March 2014, these plays made up 56% of total Permian Basin production.

[113] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

The EIA only provided projections used in its reference case tight oil forecast for the three Permian plays reviewed in detail above.[114] The aggregate production of these plays compared to the collective forecast of the EIA for them is illustrated in Figure 2-76. The EIA forecast suggests these plays will collectively produce 9.25 billion barrels between 2014 and 2040, which is nearly five times as much oil as they produced in the previous 34 years. Production is projected to rise to a peak in 2021 followed by a gradual decline through 2040, when these plays are forecast to be producing 770,000 barrels per day, or 6% above current levels. This is a very aggressive forecast considering their age and extensive drilling and production history, their relatively low quality wells, and their observed steep well- and field-declines.

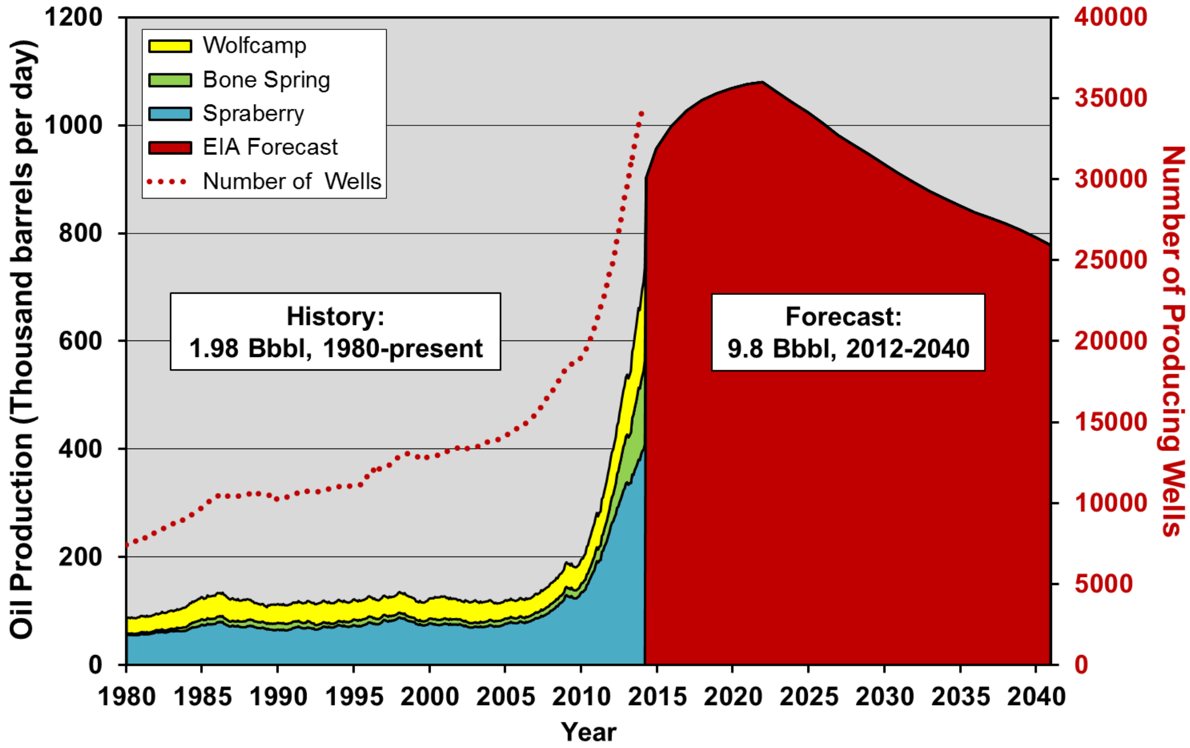


Figure 2-76. Oil production and number of producing wells in the Spraberry, Wolfcamp, and Bone Spring plays to 2014, with EIA reference case projection for these plays through 2040.[115]

The forecast total recovery of 9.8 billion barrels over the 2012-2040 period amounts to nearly five times the 1.98 billion barrels recovered from 1980 to the present, and 73% of the plays "unproved technically recoverable resources as of January 1, 2012.[116]

[114] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[115] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[116] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

Growth in the Permian Basin plays is largely a result of redevelopment of long-established plays with better technology, including horizontal drilling and fracking, rather than the new discoveries represented by the Bakken and Eagle Ford. Most of the Permian plays first began to produce significant amounts of oil and gas back in the 1950s. More than 70,000 wells have been drilled of which 43,000 are currently producing. As such they are not analogues to the Bakken and Eagle Ford, from which significant production is just twelve and six years old, respectively. The Bakken and Eagle Ford currently produce 62% of all U.S. tight oil (Figure 5), compared to 25% for the Permian plays. At least some of the oil produced from these so-called Permian "tight oil" plays is conventional, as is most of the rest of Permian Basin production. Table 2-3 summarizes the long history of development of these Permian Basin plays and contrasts that with the EIA's tight oil forecast.

Play	Years Produced	Wells Drilled	Wells Producing	Production to Date (Bbbls)	EIA Recovery 2012-2040 (Bbbls)	EIA Unproved Resources as of January 1, 2012 (Bbbls)	EIA Production in 2040 (MMbbl/d)
Spraberry	60+	36756	25939	1.83	6.5	8.1	0.51
Avalon / Bone Spring	40+	5287	2473	0.21	0.7	2.0	0.05
Wolfcamp	60+	12837	6124	0.87	2.6	3.4	0.22
Delaware	60+	8468	3995	0.43	Not Stated	Not Stated	Not Stated
Glorieta-Yeso	60+	9365	4492	0.59	Not Stated	Not Stated	Not Stated
Total		72713	43023	3.93	9.8+	13.5+	0.78+

Table 2-3. Age, wells, production[117], EIA unproved technically recoverable resources[118] and EIA reference case forecast for Permian Basin tight oil plays.[119]

[117] Data from Drillinginfo retrieved July 2014.
[118] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[119] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

2.4.5 Permian Basin Plays Analysis Summary

Several conclusions can be made from the foregoing analysis of the Permian Basin plays:

1. Growth in Permian Basin production is largely a result of application of new technologies to old plays, rather than significant new discoveries such as represented by the Bakken and Eagle Ford, although there are some emerging Permian plays lumped by the EIA into "other" in its reference case tight oil forecast.[120]

2. Productivity of wells in Permian tight oil plays is generally much lower on average than in the Bakken and Eagle Ford. Well costs are also lower with both vertical and horizontal development possible, and extensive infrastructure is in place, hence improving the economics of drilling despite the lower well productivity.

3. These plays exhibit steep well- and field-declines mandating continuous high levels of drilling and capital input to maintain production, although in the Spraberry declines are somewhat lower than in the other Permian plays.

4. The EIA is projecting aggressive continued growth in production from these plays with a peak in 2021 followed by a gradual decline, and the recovery of nearly five times as much oil by 2040 as these plays have produced in the past 34 years. This forecast is highly optimistic given the number of wells that would have to be drilled and the amount of capital required.

5. Although these plays were not reviewed on a detailed county-by-county basis, they are highly likely to exhibit "sweet spots" or "core areas" which are being targeted first, hence the number of wells and capital input will need to increase later in the EIA's forecast to moderate production decline.

[120] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA. Note that the EIA did not provide play specific projections for the Glorieta-Yeso and Delaware plays.

2.5 OTHER MAJOR PLAYS

Two other plays with significant production were singled out by the EIA[121] in its reference case tight oil forecast: the Austin Chalk in the Gulf Coast region and the Niobrara-Codell, in Colorado and Wyoming (a projection for the Monterey was also provided by the EIA but has been dealt with in a previous report[122], and the Woodford Shale, which was also provided, has relatively insignificant oil production). These are reviewed below.

[121] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[122] J. David Hughes, *Drilling California: A Reality Check on the Monterey Shale*, Post Carbon Institute, 2013, http://www.postcarbon.org/publications/drilling-california.

2.5.1 Austin Chalk Play

The EIA forecasts recovery of 4.9 billion barrels of oil from the Austin Chalk play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is highly unlikely to be realized.

The Austin Chalk play has, like the Permian plays, been producing oil and gas for decades. Over 15,000 wells have been drilled of which 5,000 are currently producing. The play has produced 1.17 billion barrels of oil and 6.1 trillion cubic feet of natural gas over its lifetime. Figure 2-77 illustrates well distribution within the Austin Chalk play. The play has seen the application of horizontal drilling for many years. Figure 2-78 illustrates the distribution of horizontal wells in the play which tend to be concentrated within certain areas.

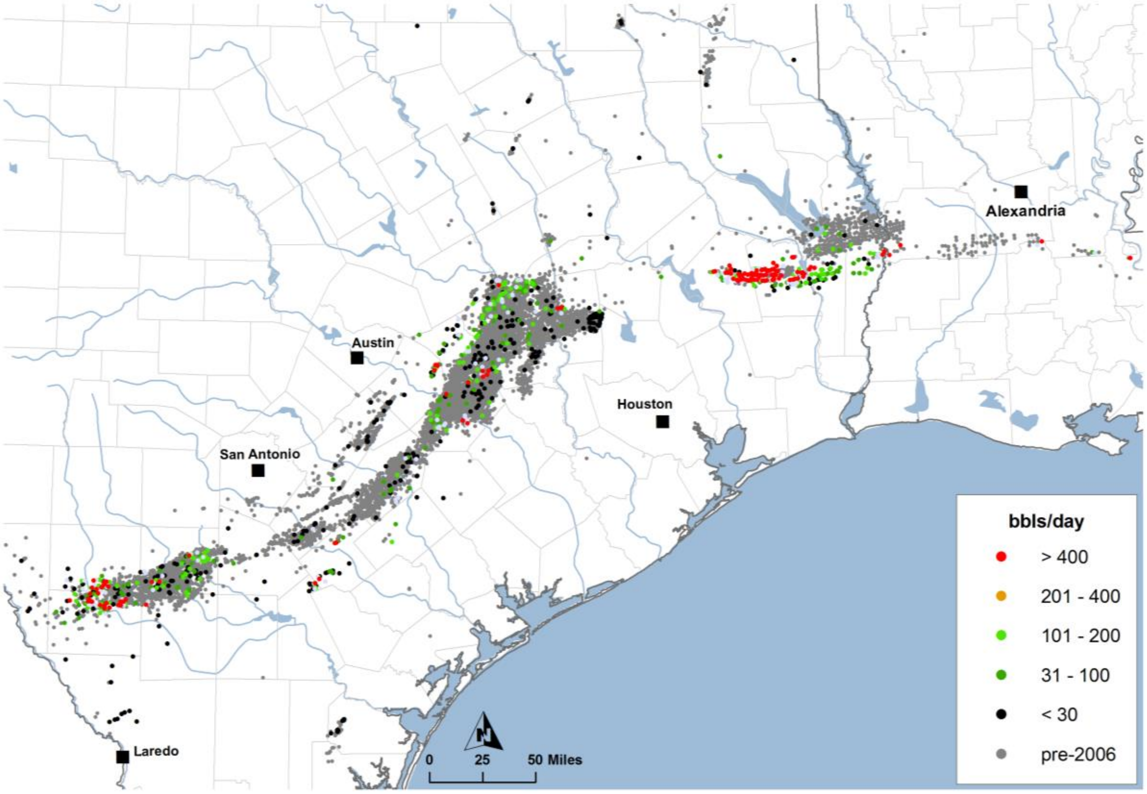


Figure 2-77. Distribution of wells in the Austin Chalk play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[123]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[123] Data from Drillinginfo retrieved July 2014.

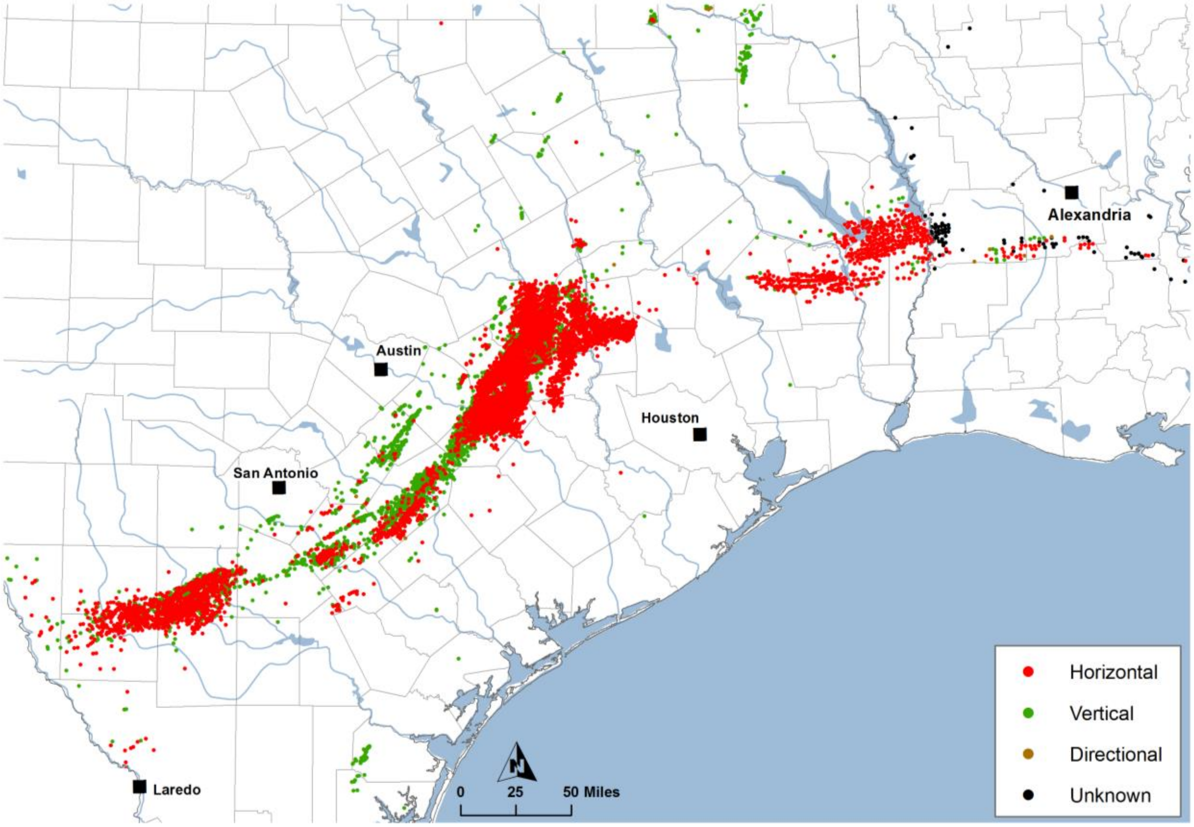


Figure 2-78. Distribution of wells in the Austin Chalk play categorized by drilling type, as of early 2014.[124]

[124] Data from Drillinginfo retrieved July 2014.

2.5.1.1 Production History

Production of oil in the Austin Chalk has been declining and the number of producing wells is also falling as illustrated in Figure 2-79. Oil production has declined by 83% since its peak in 1991.

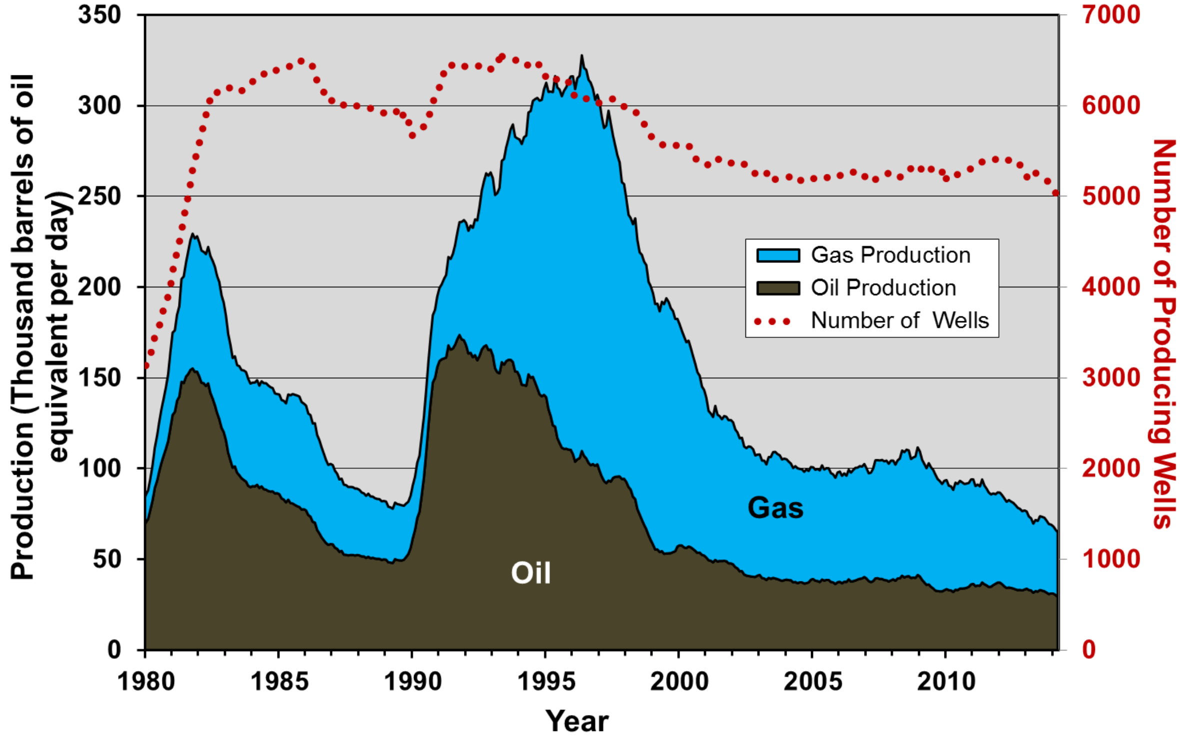


Figure 2-79. Austin Chalk play oil and gas production and number of producing wells, 1980 to 2014.[125]

Producing well count is now about 5,000.

[125] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

A look at the split in production by well type reveals that horizontal wells have contributed the bulk of oil production over the past 25 years and currently provide 90% of production (Figure 2-80).

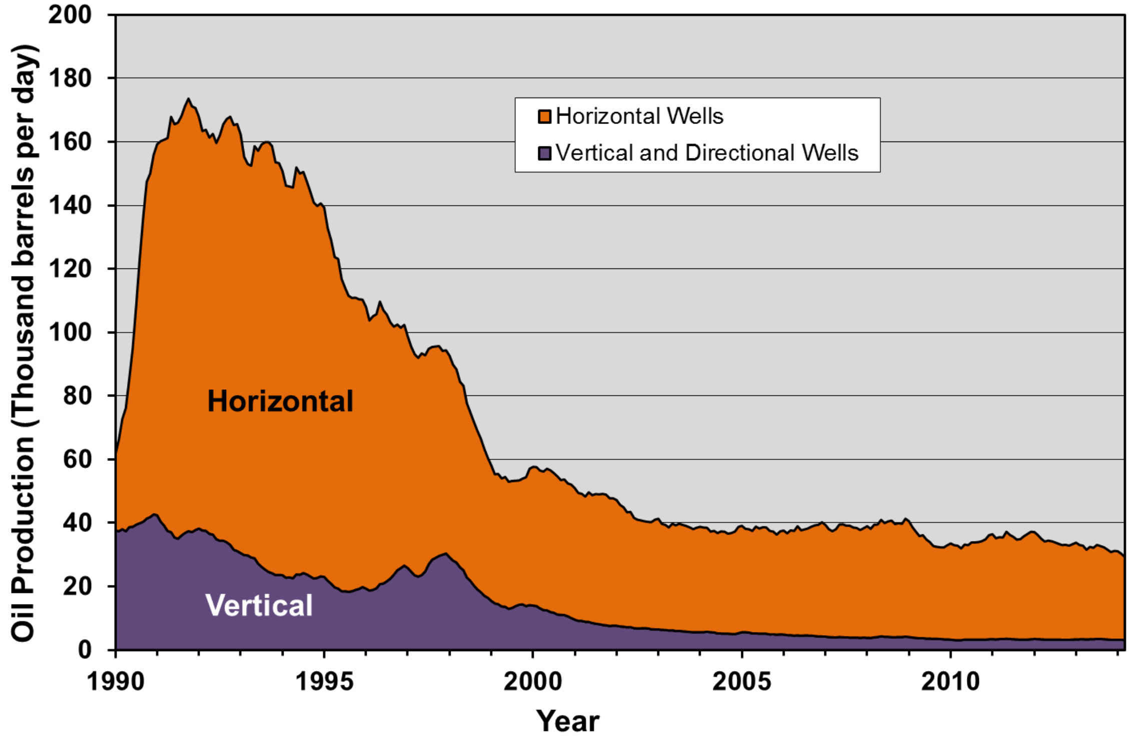


Figure 2-80. Oil production from the Austin Chalk play by well type.[126]
Horizontal wells have been the major contributors since the early 1990s.

[126] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.5.1.2 Well Quality

A look at well quality reveals that the Austin Chalk is, like the Permian Basin plays, unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-81 illustrates the average well decline profile for all wells; Figure 2-82 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are about one third of the initial production of an average Bakken well in a top county. Horizontal wells are slightly better (although 90% of "all" wells are horizontal so the only slight improvement is not surprising), although the initial productivity of the average well still pales by comparison to a Bakken or Eagle Ford well. The average three-year decline in oil production of Austin Chalk wells is comparable to the Bakken at 85% for all wells and for horizontal wells.

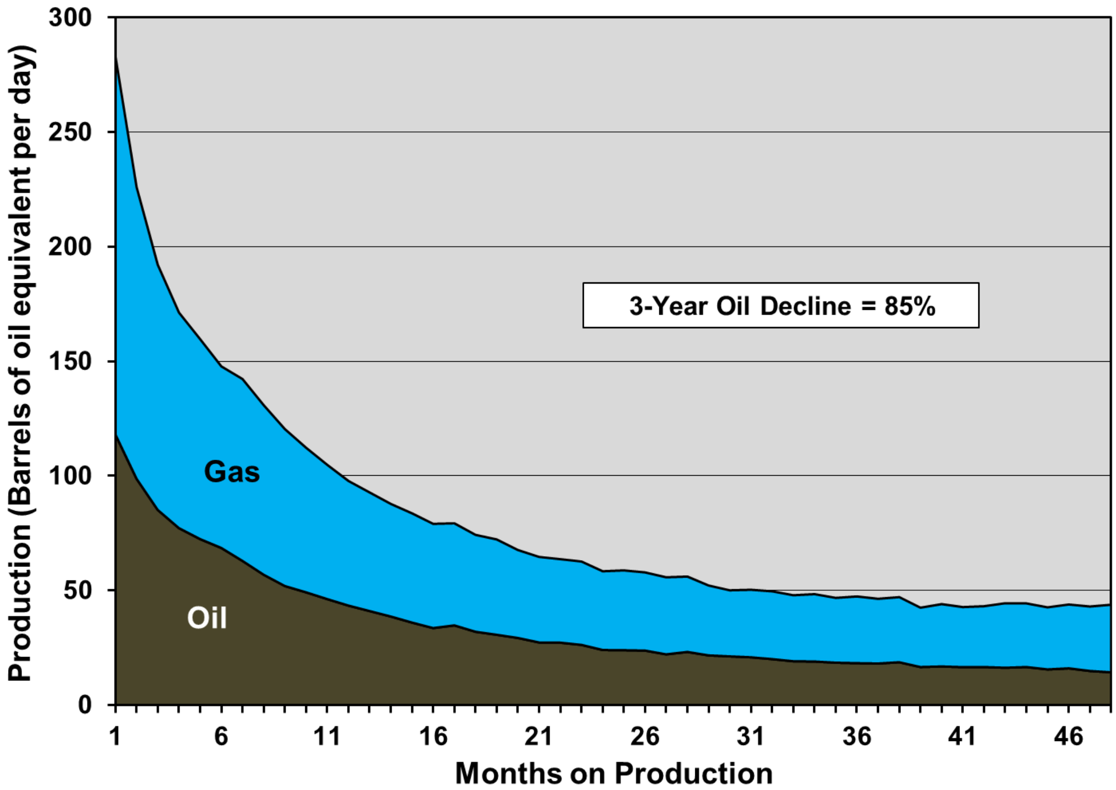


Figure 2-81. Oil and gas average well decline profile for all wells in the Austin Chalk play.[127]

On an energy equivalent basis these wells have an initial productivity of about one third that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[127] Data from Drillinginfo retrieved July 2014.

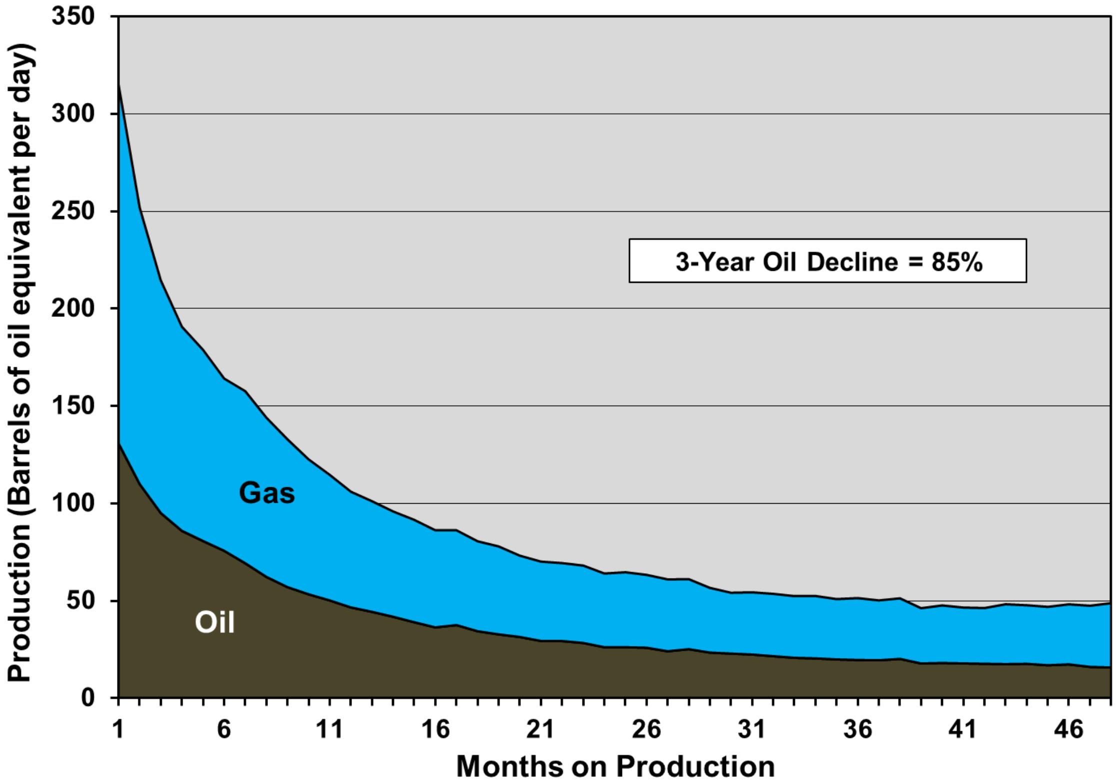


Figure 2-82. Oil and gas average well decline profile for horizontal wells in the Austin Chalk play.[128]

On an energy equivalent basis these wells have an initial productivity of about one third of the average horizontal well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[128] Data from Drillinginfo retrieved July 2014.

2.5.1.3 EIA Forecast

The EIA's projection for Austin Chalk play production through 2040 in its reference case is illustrated in Figure 2-83. Total recovery between 2012 and 2040 is forecast to be 4.9 billion barrels. This amounts to 11.3% of its U.S. reference case tight oil production through 2040. Cumulative production by 2040 amounts to 65% of the "unproved technically recoverable resources" the EIA estimated for the Austin Chalk as at January 1, 2012.

In this case the EIA's forecast looks extremely optimistic. They are projecting a production rise to a peak in 2031, at 656,830 barrels per day, which is 20 times current production, followed by a gradual decline to 513,000 barrels per day in 2040—16 times current production. As noted earlier, production in this play along with well count is falling, and well- and field-decline rates are high. In year one this forecast is already off by 145% on the high side. Given what is known, this EIA forecast would seem to have a very high optimist bias.

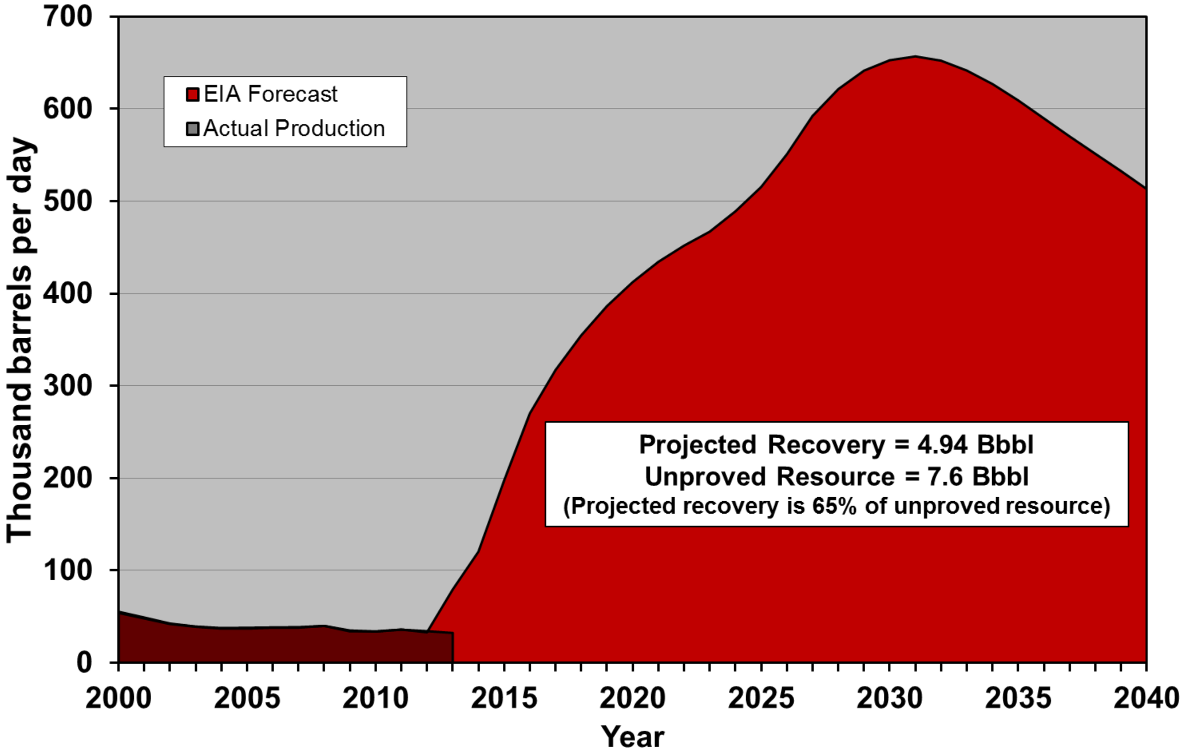


Figure 2-83. EIA reference case projection of oil production from the Austin Chalk through 2040, with actual production to 2013.[129]

The forecast total recovery of 4.94 billion barrels over the 2012-2040 period amounts to 65% of the 7.6 billion barrels of the EIA's "unproved technically recoverable resources as of January 1, 2012.[130]

[129] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[130] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.5.2 Niobrara-Codell Play

The EIA forecasts recovery of 4.9 billion barrels of oil from the Niobrara-Codell play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Niobrara-Codell play, like the Permian Basin plays and the Austin Chalk play, has been producing oil and gas for decades. Over 30,800 wells have been drilled of which 13,900 are currently producing. The play has produced 357 million barrels of oil and 3.8 trillion cubic feet of natural gas over its lifetime. Figure 2-84 illustrates well distribution within the Niobrara-Codell play. Figure 2-85 illustrates the distribution of wells in the Wattenberg Field located mainly in Weld County of Colorado, where much of the drilling has occurred.

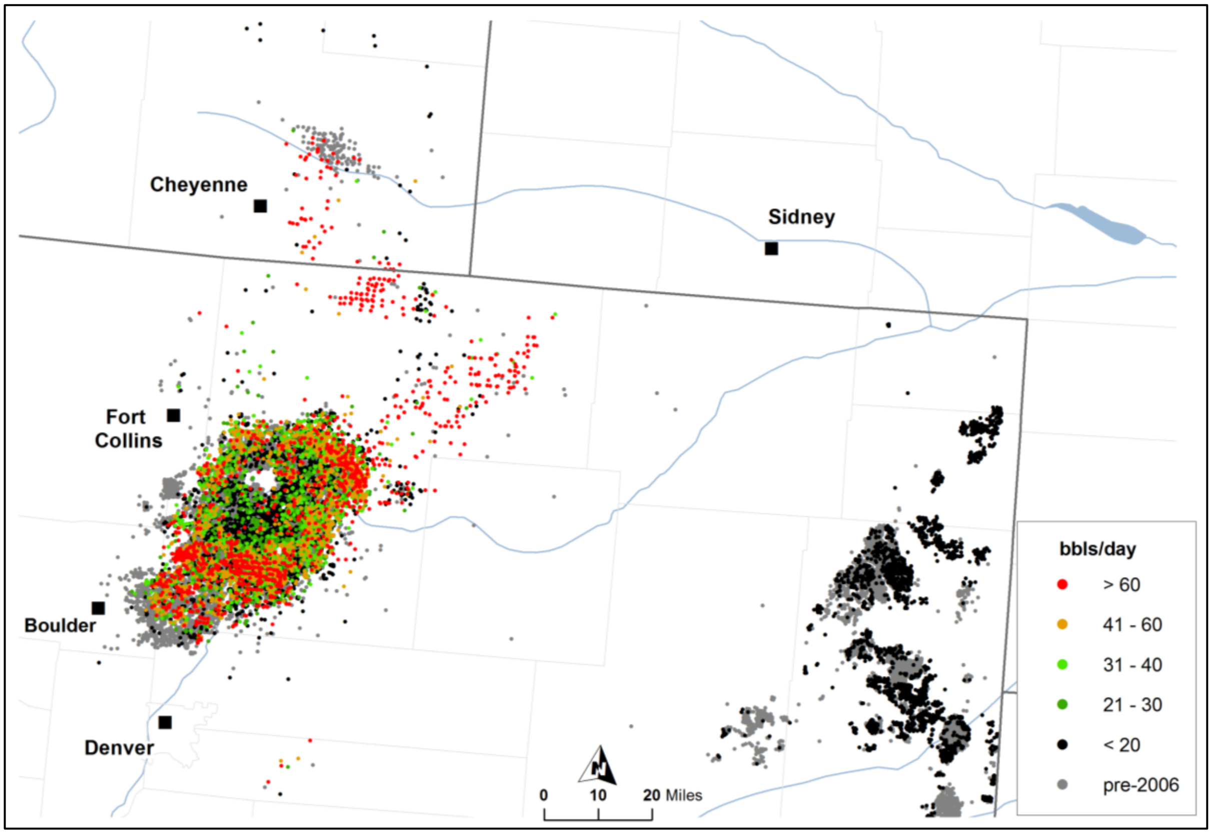


Figure 2-84. Distribution of wells in the Niobrara-Codell play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[131]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[131] Data from Drillinginfo retrieved July 2014.

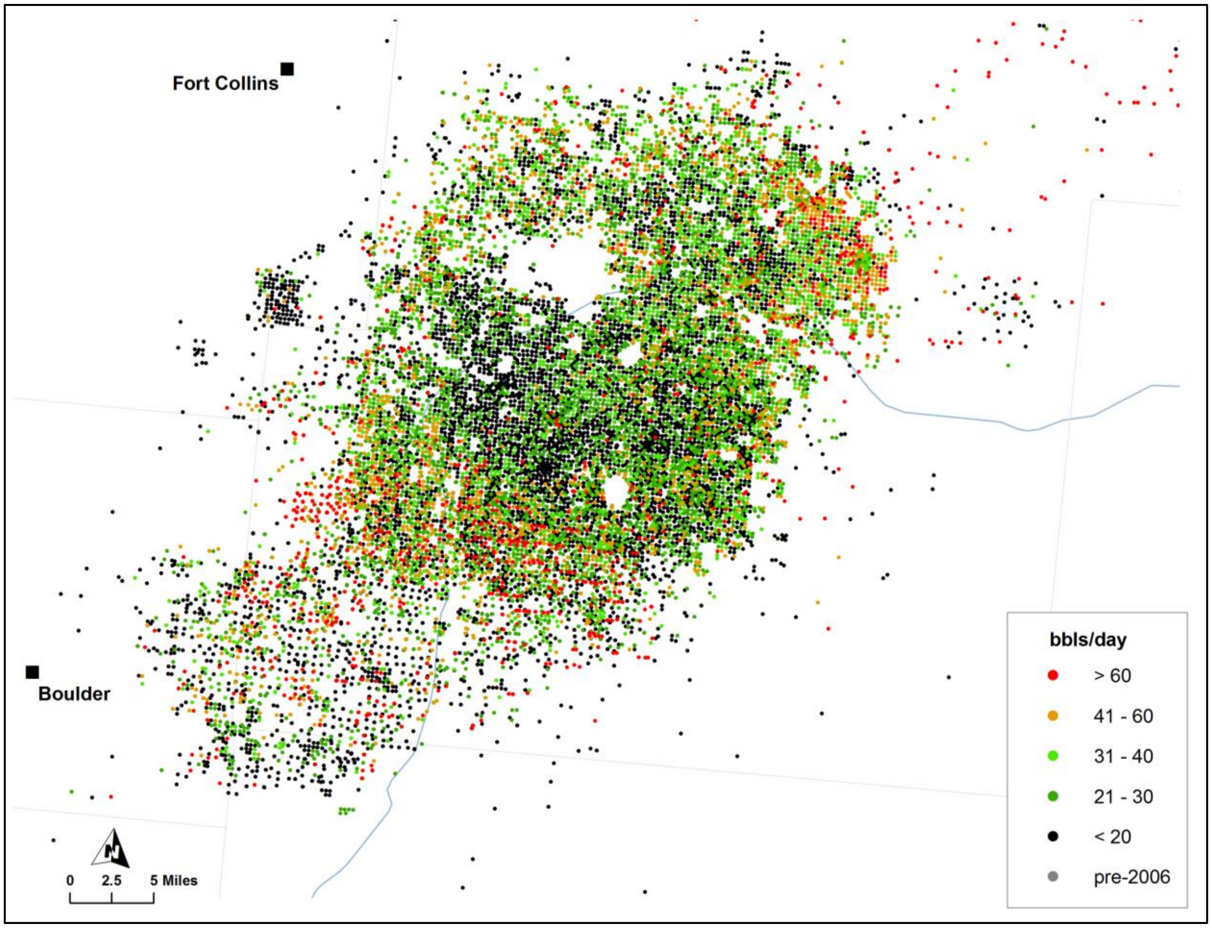


Figure 2-85. Detail of Niobrara-Codell play showing distribution of wells as of mid-2014, illustrating highest one-month oil production (initial productivity, IP).[132]

Map shows the Wattenberg Field of Weld County, Colorado, where much of the drilling has occurred. Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[132] Data from Drillinginfo retrieved July 2014.

2.5.2.1 Production History

Production of oil in the Niobrara-Codell has been growing although the number of producing wells has been falling recently as illustrated in Figure 2-86 (this may in part be related to flooding that occurred in Colorado in late 2013). Oil production hit an all-time high in December 2013, but has declined by 18% since then (again possibly related to the flooding).

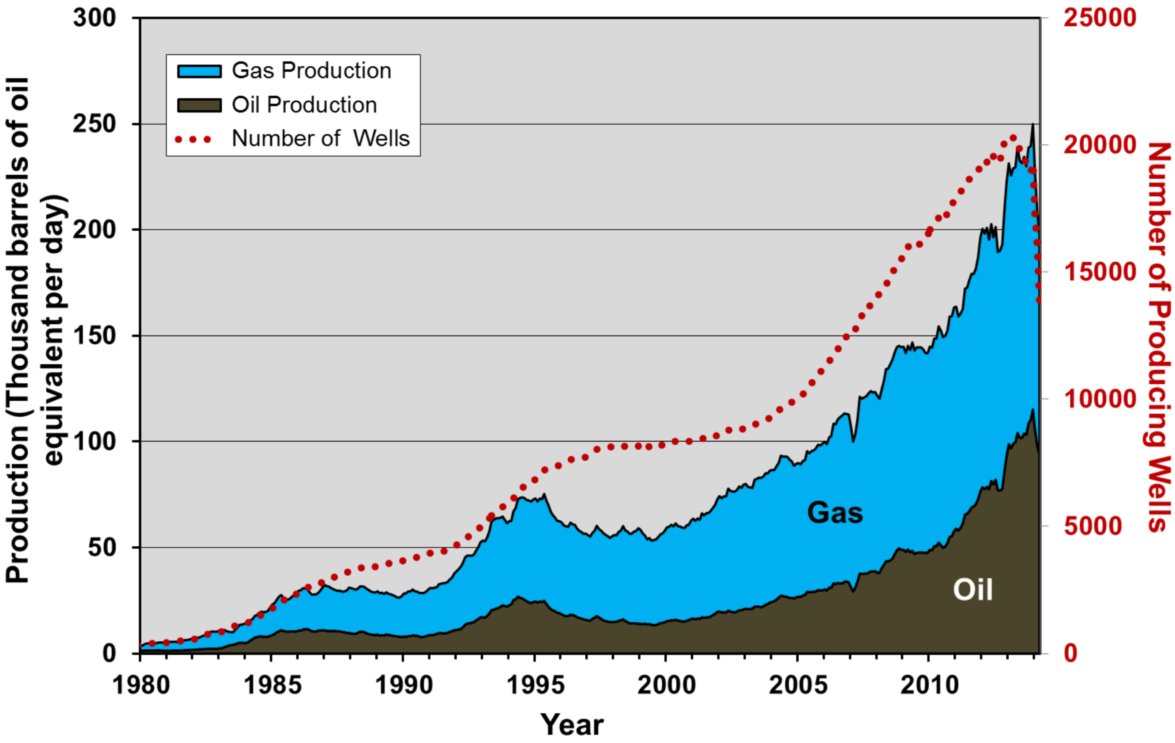


Figure 2-86. Niobrara-Codell play oil and gas production and number of producing wells, 1980 to 2014.[133]

Producing well count is now about 13,900.

[133] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

A look at the split in production by well type reveals that horizontal wells now account for 77% of oil production (Figure 2-87).

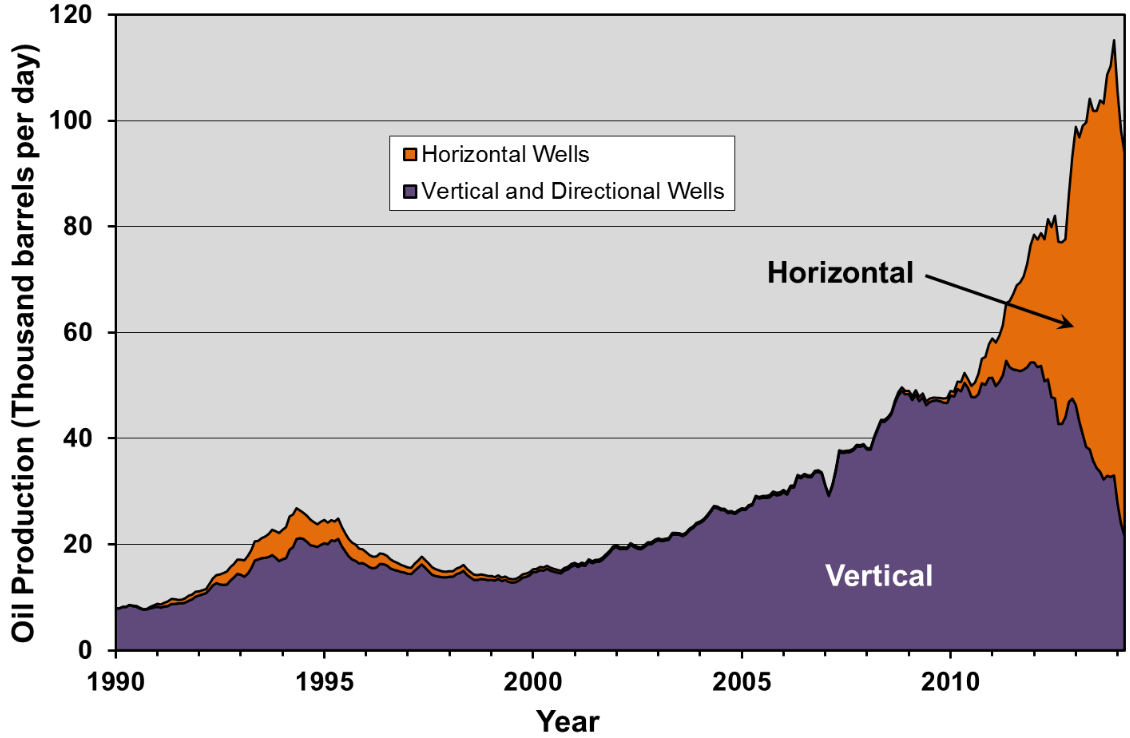


Figure 2-87. Oil production from the Niobrara-Codell play by well type.
Horizontal wells now produce 77% of the oil.[134]

[134] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.5.2.2 Well Quality

A look at well quality reveals that the Niobrara-Codell is unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-88 illustrates the average well decline profile for all wells; Figure 2-89 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are about a tenth of the initial production of an average Bakken well in a top county. Horizontal wells are much better (hence the fact that they now make up 77% of production), although the initial productivity of the average well still pales by comparison to a Bakken or Eagle Ford well. The average three-year decline of Niobrara-Codell wells is higher than that of the Bakken at 93% for all wells and 90% for horizontal wells.

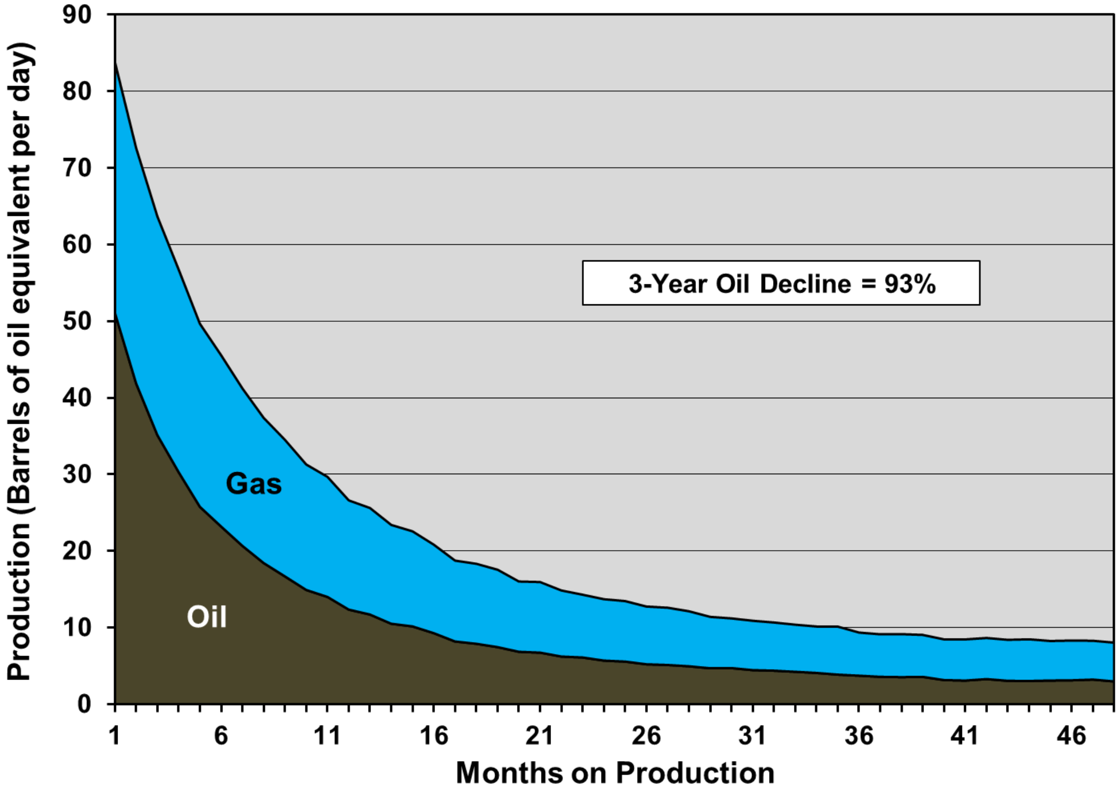


Figure 2-88. Oil and gas average well decline profile for all wells in the Niobrara-Codell play.[135]

On an energy equivalent basis these wells have an initial productivity of about a tenth that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[135] Data from Drillinginfo retrieved July 2014.

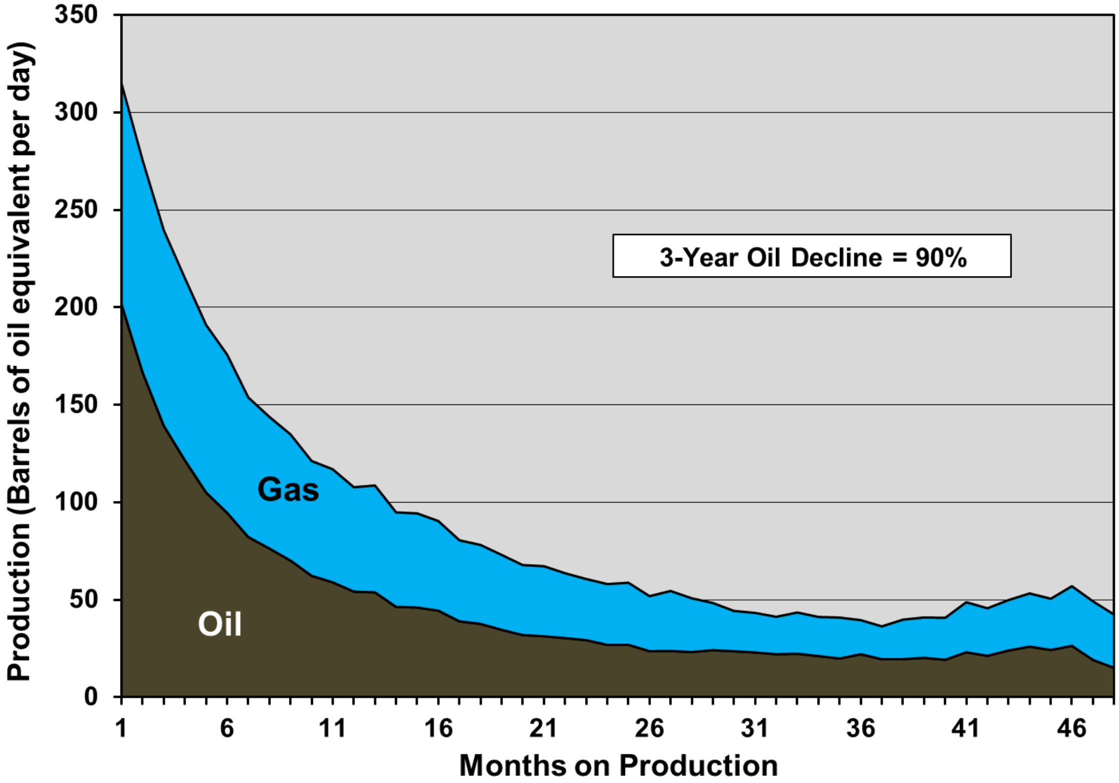


Figure 2-89. Oil and gas average well decline profile for horizontal wells in the Niobrara-Codell play.[136]

On an energy equivalent basis these wells have an initial productivity of about one third of the average horizontal well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[136] Data from Drillinginfo retrieved July 2014.

2.5.2.3 EIA Forecast

The EIA's projection for Niobrara-Codell play production through 2040 in its reference case is illustrated in Figure 2-90. Total recovery between 2012 and 2040 is forecast to be 4.9 billion barrels. This amounts to 4% of its U.S. reference case tight oil production through 2040. Cumulative production by 2040 is much higher than the resource estimate, amounting to 423% of the "unproved technically recoverable resources" the EIA estimated for the Niobrara-Codell as at January 1, 2012.

Notwithstanding the apparent overestimate of the EIA's production forecast compared to resources, the forecast has already been exceeded by production in year one. Nonetheless, the EIA projects that production will be double current levels in 2031 followed by a gradual decline to 76% above current levels in 2040. Given the very high well and field declines, among the highest of any play examined to date, this EIA forecast would seem to have a high optimist bias.

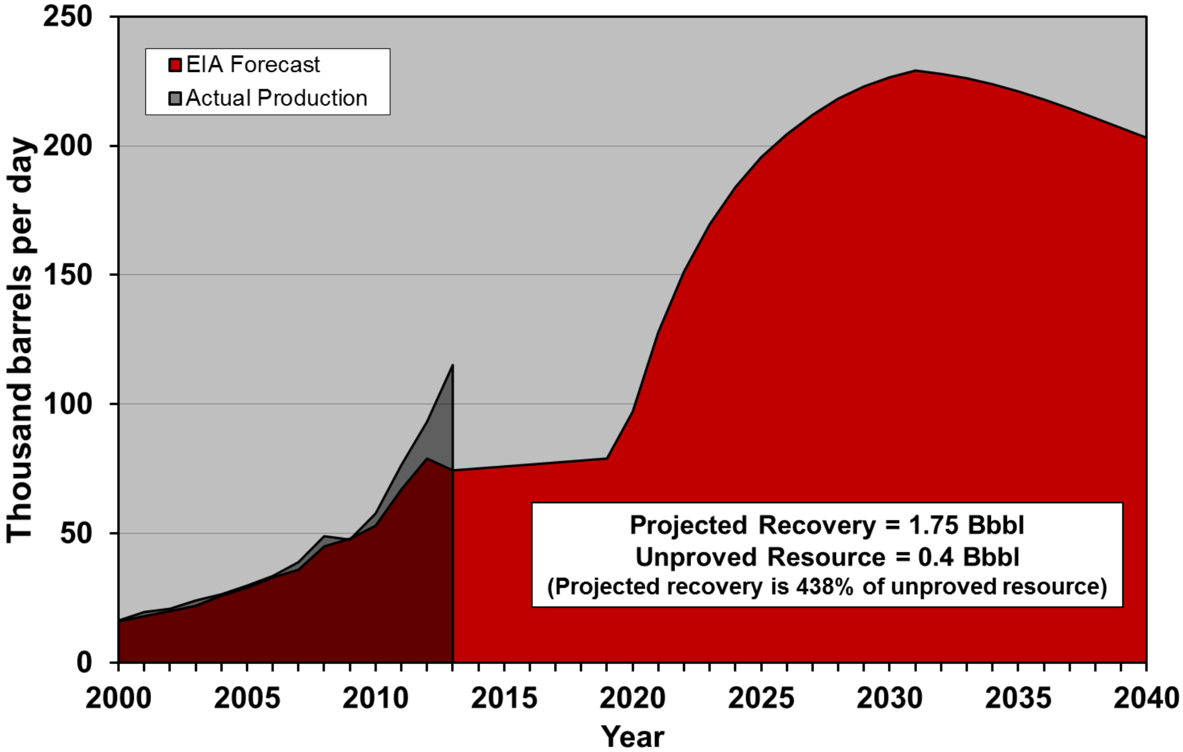


Figure 2-90. EIA reference case projection of oil production from the Niobrara-Codell through 2040, with actual production to 2013.[137]

The forecast total recovery of 1.75 billion barrels over the 2012-2040 period amounts to 438% of the 0.4 billion barrels of the EIA's "unproved technically recoverable resources as of January 1, 2012."[138]

[137] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[138] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.5.3 Key Characteristics of the Austin Chalk and Niobrara-Codell Plays

The Austin Chalk and Niobrara-Codell plays are together projected to account for 15.3% of the tight oil production in the EIA's reference case tight oil forecast[139] (the two other plays for which the EIA provided individual play projections, the Woodford and Monterey, contribute only 2.4%). The EIA suggests these plays will collectively produce 6.6 billion barrels between 2014 and 2040, which is more than four times as much oil as they produced since their discoveries more than 40 years ago. Production is projected to rise to a peak in 2031 at 890,000 barrels per day followed by a gradual decline through 2040, when these plays are forecast to still be producing 720,000 barrels per day, which is nearly five times current levels (current combined production is 147,000 barrels per day[140]). This is a very aggressive forecast considering their age and extensive drilling and production history, their relatively low quality wells, and their observed steep well- and field-declines.

Production growth in the Austin Chalk and Niobrara-Codell plays is largely a result of redevelopment of long established plays with better technology, including horizontal drilling and fracking, rather than the new discoveries represented by the Bakken and Eagle Ford. The Austin Chalk began production in the 1950s and the Niobrara-Codell in the 1970s. More than 46,000 wells have been drilled of which 18,800 are currently producing. As such they are not analogues to the Bakken and Eagle Ford, from which significant production is just twelve and six years old, respectively. The Bakken and Eagle Ford currently produce 62% of all U.S. tight oil (Figure 5), compared to 5.3% for the Austin Chalk and Niobrara-Codell. At least some of the oil produced from these so-called "tight oil" plays is conventional. Table 2-4 summarizes the long history of development of these plays and contrasts that with the expectations for them in EIA's tight oil forecast.

Play	Years Produced	Wells Drilled	Wells Producing	Production to Date (Bbbls)	EIA Recovery 2012-2040 (Bbbls)	EIA Unproved Resources as of January 1, 2012 (Bbbls)	EIA Production in 2040 (MMbbl/d)
Austin Chalk	60+	15308	4988	1.17	4.9	7.6	0.51
Niobrara-Codell	40+	30871	13888	0.36	1.8	0.4	0.20
Total		46179	18876	1.53	6.7	8.0	0.72

Table 2-4. Age, wells, production[141], EIA unproved technically recoverable resources[142] and EIA reference case forecast for the Austin Chalk and Niobrara-Codell plays.[143]

Numbers may not add due to rounding.

---

139 EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
140 Data from Drillinginfo retrieved July 2014.
141 Data from Drillinginfo retrieved July 2014.
142 EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
143 EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

2.5.4 Austin Chalk and Niobrara-Codell Plays Analysis Summary

Several conclusions can be made from the foregoing analysis of the Austin Chalk and Niobrara-Codell plays:

1. Oil production in the Austin Chalk and Niobrara-Codell plays is largely a result of application of new technologies to old plays, rather than significant new discoveries such as represented by the Bakken and Eagle Ford. Despite the application of new technology oil production in the Austin Chalk is falling, and the Niobrara-Codell may have peaked.

2. Productivity of wells in the Austin Chalk and Niobrara-Codell plays is generally much lower on average than in the Bakken and Eagle Ford. Well costs may also be somewhat lower, although most new production utilizes horizontal drilling, and extensive infrastructure is in place, hence improving the economics of drilling despite the lower well productivity.

3. These plays exhibit steep well- and field-declines mandating continuous high levels of drilling and capital input to maintain production.

4. The EIA is projecting aggressive growth in production from these plays with a peak in 2031 followed by a gradual decline, and the recovery of more than four times as much oil by 2040 as they have produced since their discoveries more than 40 years ago. This forecast is extremely optimistic given the number of wells that would have to be drilled and the amount of capital required.

5. Although these plays were not reviewed on a detailed county-by-county basis, they are highly likely to exhibit “sweet spots” or “core areas” which are being targeted first, hence the number of wells and capital input will need to increase later in the EIA’s forecast to moderate production decline.

2.6 ALL-PLAYS ANALYSIS

The foregoing analysis has reviewed—on a play-by-play basis—82% of the projected U.S. tight oil production in the EIA reference case forecast through 2040. Eighty percent of this projected production has a "high" or "very high" optimism bias, suggesting that actual production is likely to be far less than that projected by the EIA over the long term. Moreover, the analysis suggests that the Bakken and Eagle Ford plays will remain the foundation of the U.S. tight oil "shale revolution." The plays outside of the Bakken and Eagle Ford are mainly redevelopments of old plays, with tens of thousands of wells drilled over the preceding 40 to 60 years. Despite the EIA's assertion, for example, that Permian Basin plays such as the Spraberry, Wolfcamp, and Bone Spring "have initial well production rates comparable to those found in the Bakken and Eagle Ford shale formations"[144], this is belied by the actual data. Average initial oil well productivities of these plays are a half or less of the average initial production of a high quality county in the Bakken or Eagle Ford.

This section will further explore the outlook for overall U.S. tight oil production with a summary analysis of the plays' EIA forecasts, estimated ultimate recovery per well, associated natural gas production, and production prospects to 2040.

[144] EIA, "Six formations are responsible for surge in Permian Basin crude oil production," *Today in Energy*, July 9, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=17031.

2.6.1 Summary of EIA Forecasts

Table 2-5 summarizes the salient details of the EIA's tight oil production projections and estimates of "unproved technically recoverable resources" and "proved reserves"; it also includes historical production for context, and an "optimism bias" rating.

Play	EIA Projected Recovery 2012-2040 (Bbbls)	Production to Date (Bbbls)[145]	EIA Unproved Resources as of January 1, 2012 (Bbbls)	EIA Proved Reserves as of 2012 (Bbbls)	EIA Total Proved and Unproved Technically Recoverable (Bbbls)	Percent of Unproved Resources and Proved Reserves Recovered by 2040 in EIA Forecast	Play's Share of Total Recovery (%)	EIA Production in 2040 (MMbbl/d)	Optimism Bias
Bakken	8.4	1.16	9.2	3.12	12.32	68.3	19.3	0.45	High
Eagle Ford	10.7	0.90	9.3	3.37	12.67	84.8	24.6	0.59	High
Woodford	0.4	0.03	0.2	--	0.20	207.4	1.0	0.03	Very High
Austin Chalk	4.9	1.17	7.6	--	7.60	65.0	11.3	0.51	Very High
Spraberry	6.5	1.83	8.1	--	8.10	80.0	14.9	0.51	Very High
Niobrara	1.8	0.36	0.4	0.01	0.41	423.8	4.0	0.20	High
Avalon/Bone Spring	0.7	0.21	2.0	--	2.00	34.1	1.6	0.05	Low
Monterey	0.6	--	0.6	--	0.60	102.3	1.4	0.06	High
Wolfcamp	2.6	0.87	3.4	--	3.40	77.6	6.1	0.22	High
Other	6.9	1.50	18.4	0.65	19.05	36.3	15.8	0.58	Unknown
Total	**43.6**	**8.03**	**59.2**	**7.15**	**66.35**	**65.7**	**100.0**	**3.20**	High to Very High

Table 2-5. Summary of EIA reference case tight oil forecast and assumptions[146] and stated unproved technically recoverable resources[147] and proved reserves[148], with historical production and "optimism bias" rating.[149]

The "optimism bias" rating is based on the analysis in this report.

[145] "Other" category estimated: Delaware and Glorieta-Yeso plays have cumulative production of 1.02 Bbbls over the last 40+ years and 0.48 Bbbl is estimated for other plays, which include the Utica, Tuscaloosa Marine Shale, Albany and others including liquids produced from shale gas plays.
[146] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[147] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[148] EIA, http://www.eia.gov/naturalgas/crudeoilreserves/index.cfm.
[149] Data from Drillinginfo retrieved May-July 2014.

2.6.2 Estimated Ultimate Recovery per Well

Average per-well estimated ultimate recovery (EUR) for each of the analyzed plays is illustrated in Figure 2-91. These EURs are offered for comparative purposes only; each play is treated the same, with the average well decline data used in the first three years followed by an exponential decline at a terminal decline rate (the jury is out on the actual long term oil recovery of tight oil wells). This comparison highlights that the Bakken's and Eagle Ford's per-well EURs are two to more than four times higher than that of the other plays. For all plays, high decline rates of tight oil wells mean that 43% to 64% of the EUR is recovered in the first three years.

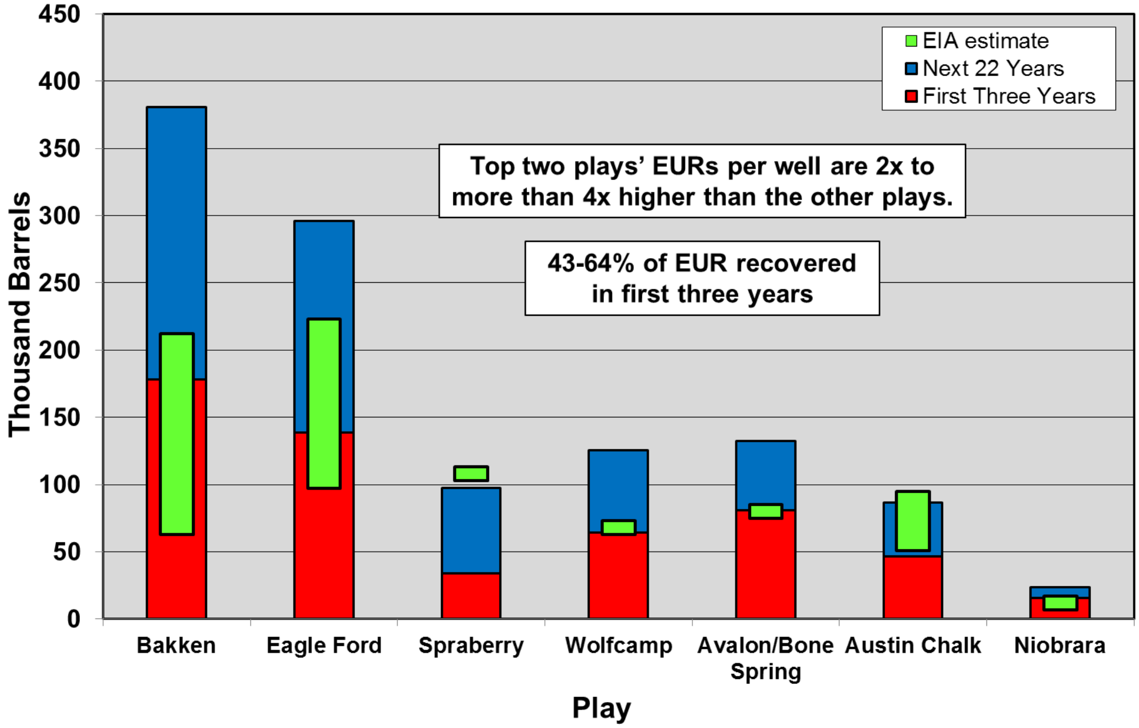


Figure 2-91. Estimated ultimate recovery (EUR) of oil per well of reviewed plays.[150]

Roughly half of the EUR is recovered in the first three years due to steep decline rates. These estimates of EUR per well are generally higher than those provided by the EIA[151] which are (in Kbbls): Bakken, 63-212; Eagle Ford, 97-223; Spraberry, 108; Wolfcamp, 68; Avalon/Bone Spring, 80; Austin Chalk, 51-95; Niobrara, 12.

[150] Based on data from Drillinginfo retrieved May-July 2014.
[151] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

Horizontal wells generally improve the per-well EURs somewhat. Figure 2-92 illustrates the same comparison for horizontal wells only. Although looking at only horizontal wells markedly improves plays like the Niobrara-Codell, illustrating the difference that new technology is making, the Bakken's and Eagle Ford's EURs per well are still nearly double to triple the average well performance of the other plays.

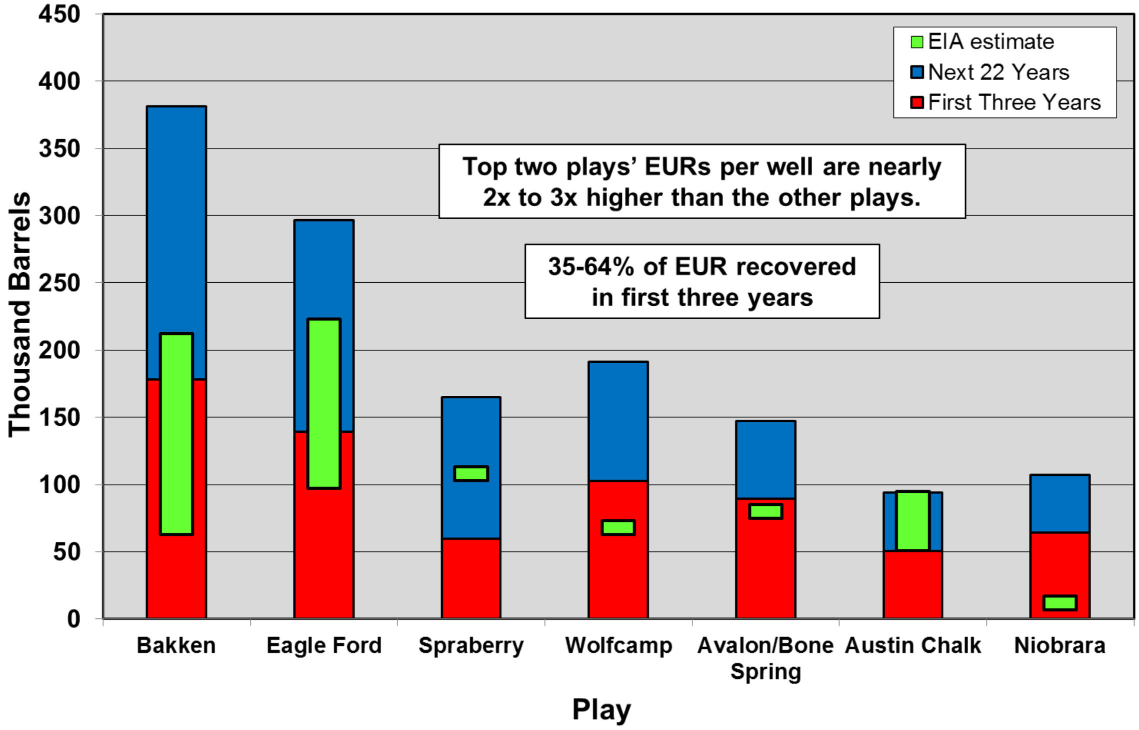


Figure 2-92. Estimated ultimate recovery (EUR) of oil per horizontal well for reviewed plays.[152]

Roughly half of the EUR is recovered in the first three years due to steep decline rates. These estimates of EUR per well are generally higher than those provided by the EIA[153] which are (in kbbls): Bakken, 63-212; Eagle Ford, 97-223; Spraberry, 108; Wolfcamp, 68; Avalon/Bone Spring, 80; Austin Chalk, 51-95; Niobrara, 12.

[152] Based on data from Drillinginfo retrieved May-July 2014.
[153] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.6.3 Natural Gas Production Component

The natural gas production component of many of these plays is also an important contributor to energy production and economics (all these plays produce both oil and gas). Natural gas can be converted to its oil energy equivalent at a ratio of 6,000 cubic feet of gas to one barrel of oil. On a price basis, however, oil is far more valuable, so whereas 1,000 cubic feet of gas is equivalent to one sixth of a barrel of oil on an energy equivalent basis, it is only equivalent to one twentieth or less of the value of a barrel of oil at current prices. Figure 2-93 illustrates the EUR comparison between plays on a "barrels of oil equivalent" basis. The same pattern holds: the Bakken's and Eagle Ford's EURs per well are two to more than six times higher than the EURs per well of the other plays.

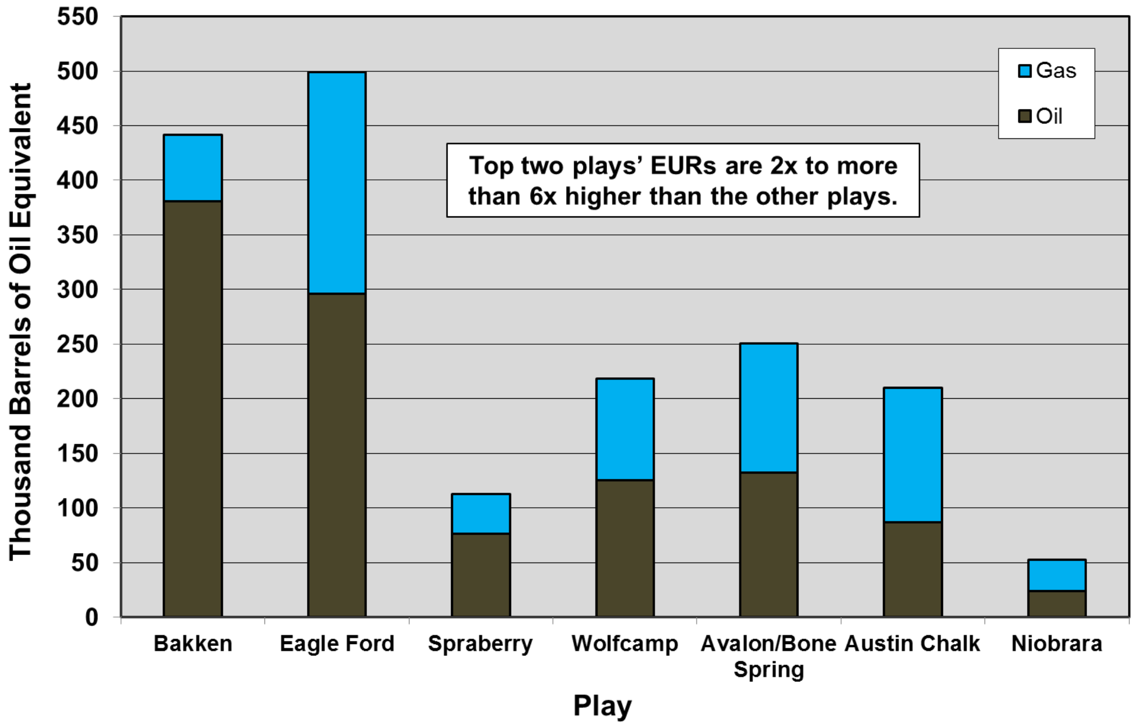


Figure 2-93. Estimated ultimate recovery (EUR) of oil and gas per well of reviewed plays, on a "barrels of oil equivalent" basis.[154]

The Bakken's and Eagle Ford's EURs per well are two to more than six times the EURs per well of the other five plays.

[154] Based on data from Drillinginfo retrieved May-July 2014.

Looking at horizontal wells only on an oil and gas EUR energy equivalency basis, production from some of these plays is considerably higher—and in plays like the Austin Chalk, Bone Spring, and Niobrara-Codell, natural gas is half or more of total energy production. Nonetheless, the Bakken's and Eagle Ford's EURs per well remain 39% to 141% higher than the other plays on an energy equivalency basis.

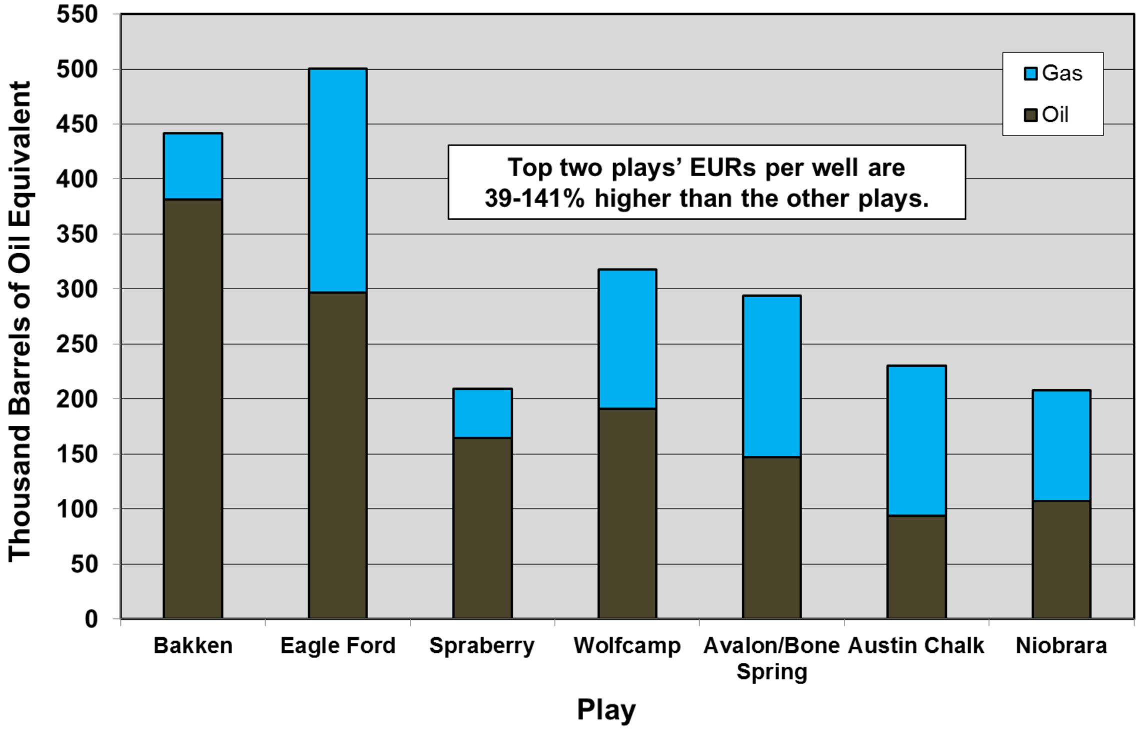


Figure 2-94. Estimated ultimate recovery (EUR) of oil and gas per horizontal well of reviewed plays, on a "barrels of oil equivalent" basis.[155]

The Bakken's and Eagle Ford's EURs per well are 34% to 141% higher than the other plays.

[155] Based on data from Drillinginfo retrieved May-July 2014.

2.6.4 Production Through 2040

This report provides tight oil production projections for the Bakken and Eagle Ford plays—which account for 62% of current production—and production history, well quality and other factors controlling future production for additional major plays which comprise a further 27% of tight oil production. The Bakken and Eagle Ford are particularly important as they are projected to account for over half of total production well into the next decade. This analysis reveals that more than two times the projected production from the Bakken and Eagle Ford will have to be produced from other plays to meet the EIA reference case forecast by 2040: a tall order which is unlikely to be realized given the fundamentals of these plays as outlined in this report.

Figure 2-95 compares the EIA's reference case projection through 2040 for tight oil production[156] to the most likely of the Bakken and Eagle Ford scenarios presented in sections 2.3.1.6 and 2.3.2.6, respectively (the "Most Likely Rate" scenarios of the "Realistic" cases of the respective plays).

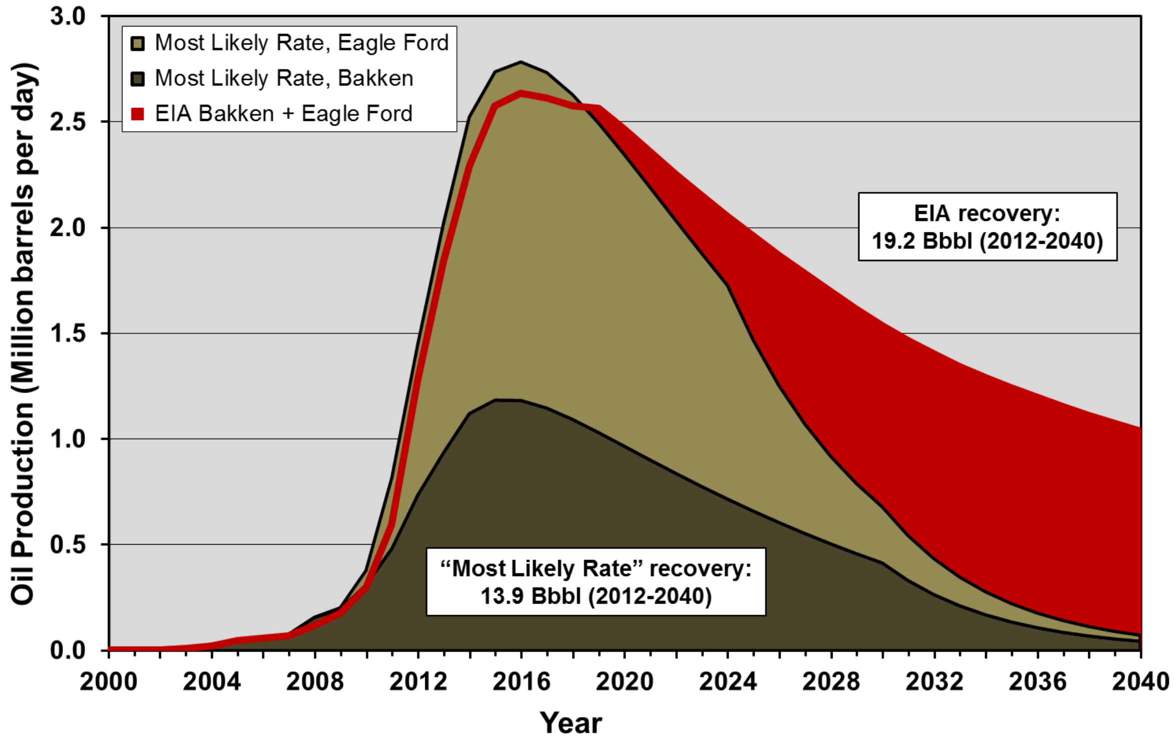


Figure 2-95. "Most Likely Rate" scenarios ("Realistic" cases) of Bakken and Eagle Ford tight oil production compared to the EIA reference case, 2000 to 2040.[157]

Total oil recovery forecast by the EIA from these plays is 19.2 billion barrels from 2012-2040 versus 13.7 billion barrels in this report.

[156] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[157] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

This comparison reveals:

- The EIA's forecast of the timing of peak production in the Bakken and Eagle Ford is similar to this report.
- The EIA's forecast of the rate at peak production is lower than this report, but only slightly.
- The EIA projects a much higher tail after peak production, with recovery of 19.2 billion barrels between 2012 and 2040, as opposed to 13.9 billion barrels forecast in this report.
- The EIA forecasts collective production from these plays to be 1 million barrels per day in 2040, suggesting considerably more oil will be recovered after that date; in contrast, the "Most Likely" drilling rate scenario presented in this report forecasts that production will fall to about 73,000 barrels per day by 2040.

The EIA's reference case projections for the Bakken and Eagle Ford require the recovery of 19.2 billion barrels by 2040. This amounts to 77% of the sum of proved reserves (6.49 billion barrels)[158] and estimated "unproved technically recoverable resources" (18.5 billion barrels)[159] claimed for these two plays. Unproved technically recoverable resources have no price constraints applied and are loosely constrained by geological parameters; to assume the recovery of 77% of proved reserves plus unproved resources by 2040 is extremely optimistic.

Moreover, the EIA's Bakken and Eagle Ford forecast amounts to the recovery of 40% more oil than this report's analysis suggests those plays can produce by 2040 (assuming capital will even be available to drill more than 51,000 additional wells in these plays at a cost of some $410 billion). The EIA's assumption that production from the Bakken and Eagle Ford will still be at more than one million barrels per day in 2040, after producing over 19.6 billion barrels since 2000, strains credibility to the limit.

The large difference between this report's projections and the EIA's forecasts for the Bakken and Eagle Ford, coupled with the high to very high optimism bias in the EIA's forecast for most of the other plays analyzed, suggests that the EIA's total U.S. tight oil forecast is likely to be seriously overstated, and hence very difficult or impossible to achieve. Figure 2-96 illustrates the production that would be required from all other tight oil plays to meet the EIA's reference case tight oil forecast from 2012 through 2040 (43.6 billion barrels), after accounting for this report's "Most Likely" scenario forecasts for the Bakken and Eagle Ford (which are 5.3 billion barrels less than the EIA's through 2040). The result is 29.7 billion barrels that must be made up from other tight oil plays, or two times the projected recovery from the Bakken and Eagle Ford by 2040 (13.9 billion barrels), over this period.

[158] EIA, "U.S. Crude Oil and Natural Gas Proved Reserves," April 2014, http://www.eia.gov/naturalgas/crudeoilreserves/index.cfm.
[159] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

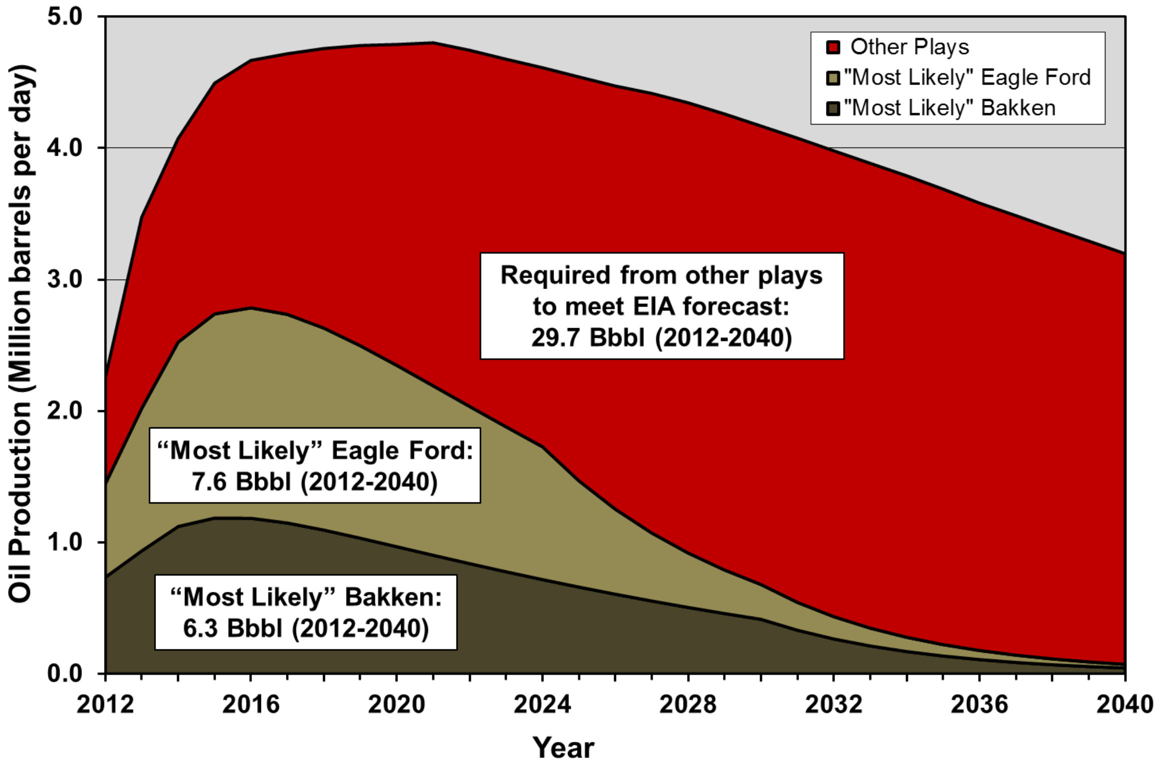


Figure 2-96. "Most Likely" scenario projections of oil production for the Bakken and Eagle Ford plays[160] with the remaining amount of production that would be required from other plays to meet the EIA's total reference case forecast.[161]

The EIA forecasts 43.6 billion barrels of U.S. tight oil will be recovered from 2012 to 2040. After subtracting the 13.9 billion barrels projected by this report for the Bakken and Eagle Ford, 29.7 billion barrels would remain to be produced from all other tight oil plays—5.3 billion barrels more than the EIA's already optimistic forecast for these plays.

[160] Data from Drillinginfo retrieved May 2014.
[161] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

2.7 SUMMARY AND IMPLICATIONS

The growth of U.S. tight oil production is one of the few bright spots contributing to global oil production growth. Geopolitical turmoil in parts of the Middle East and northern and western Africa, coupled with production declines in other major producers such as Russia[162], has kept oil prices persistently near historic highs. Investments by oil majors in upstream oil and gas production have increased three-fold since 2000 yet production is up just 14%.[163] Economist Mark Lewis points out that “the damage has been masked so far as big oil companies draw down on their cheap legacy reserves”, but that “they are having to look for oil in the deepwater fields off Africa and Brazil, or in the Arctic, where it is much more difficult. The marginal cost for many shale plays is now $85 to $90 a barrel.”[164]

Given these factors it is important to understand the long term supply limitations of U.S. tight oil. The analysis presented herein, which is based on one of the best commercial databases of well production information available[165], finds that the longevity of U.S. tight oil production at meaningful rates is highly questionable. Certainly production will rise in the short term, but with the very likely peaking of the Bakken and Eagle Ford plays (which provide 62% of current U.S. tight oil output) in the 2016-2017 timeframe, maintaining production or even stemming the decline will require ever greater amounts of drilling, along with the capital input to sustain it. This will require higher prices, for the nature of shale plays is that the sweet spots get drilled first and progressively lower quality rock gets drilled last.

Furthermore, much of the purported “tight oil” production outside of the Bakken and Eagle Ford comes from long-established plays benefiting from the application of new technology, not new discoveries. Tens of thousands of wells have been drilled in these plays over the past 40 or more years and they have produced much oil and gas, yet the EIA forecast expects them to produce 4-5 times their historical production in the next 26 years. These plays have well qualities as defined by initial productivity and EUR of less than half of the Bakken and Eagle Ford on average. The concept that high quality tight oil plays like the Bakken and Eagle Ford are widespread is false.

The EIA, which is viewed as perhaps the most authoritative source of U.S. energy production forecasts, has consistently overestimated future production.[166] The analysis presented herein suggests that this is the case with respect to tight oil. A play-by-play analysis of the data with respect to the EIA forecasts reveals a high to very high “optimism bias”. The EIA assumes that 65% to 85% of its “proved reserves and unproved technically recoverable resources as of January 1, 2012” will be recovered by 2040 for most plays. Unproved resources have no price constraints applied and are loosely constrained compared to “reserves” which are proven to be recoverable with existing technology and economic conditions. Not only do the EIA’s projections demonstrate a high or very high optimism bias, they also assume that the U.S. will exit 2040 with tight oil production comparable to today, at 3.2 MMbbl/d. This is highly unlikely given a thorough analysis of the data.

The Bakken and the Eagle Ford have produced just under 2 billion barrels of oil to date and will continue to produce much more oil, assuming drilling rates and the capital input to sustain them will be maintained. This report projects that they will produce 13.9 billion barrels from 2012 to 2040, with marginal production under

---

162 Reuters, “UPDATE 1-Russian oil output down for fourth month in a row,” May 2, 2014, http://uk.reuters.com/article/2014/05/02/russia-energy-production-idUKL6N0NO0UL20140502.
163 Mark Lewis of Kepler Cheuvreux cited in Ambrose Evans-Pritchard, “Fossil industry is the subprime danger of this cycle”, Telegraph, July 9, 2014, http://www.telegraph.co.uk/finance/comment/ambroseevans_pritchard/10957292/Fossil-industry-is-the-subprime-danger-of-this-cycle.html.
164 Ambrose Evans-Pritchard, “Fossil industry is the subprime danger of this cycle”, Telegraph, July 9, 2014.
165 DI Desktop (formerly HDPI), produced by Drillinginfo.
166 See Figure 25 in J. David Hughes, *Drill Baby Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?*, Post Carbon Institute, 2013, http://www.postcarbon.org/publications/drill-baby-drill.

0.08 MMbbl/d in 2040, given unconstrained capital input. In contrast, the EIA forecasts 19.2 billion barrels of cumulative production from these plays over the same period, with production of just over 1 MMbbl/d in 2040. Figure 2-97 illustrates the stark difference between the EIA's projections and this report's projections of Bakken and Eagle Ford tight oil production.

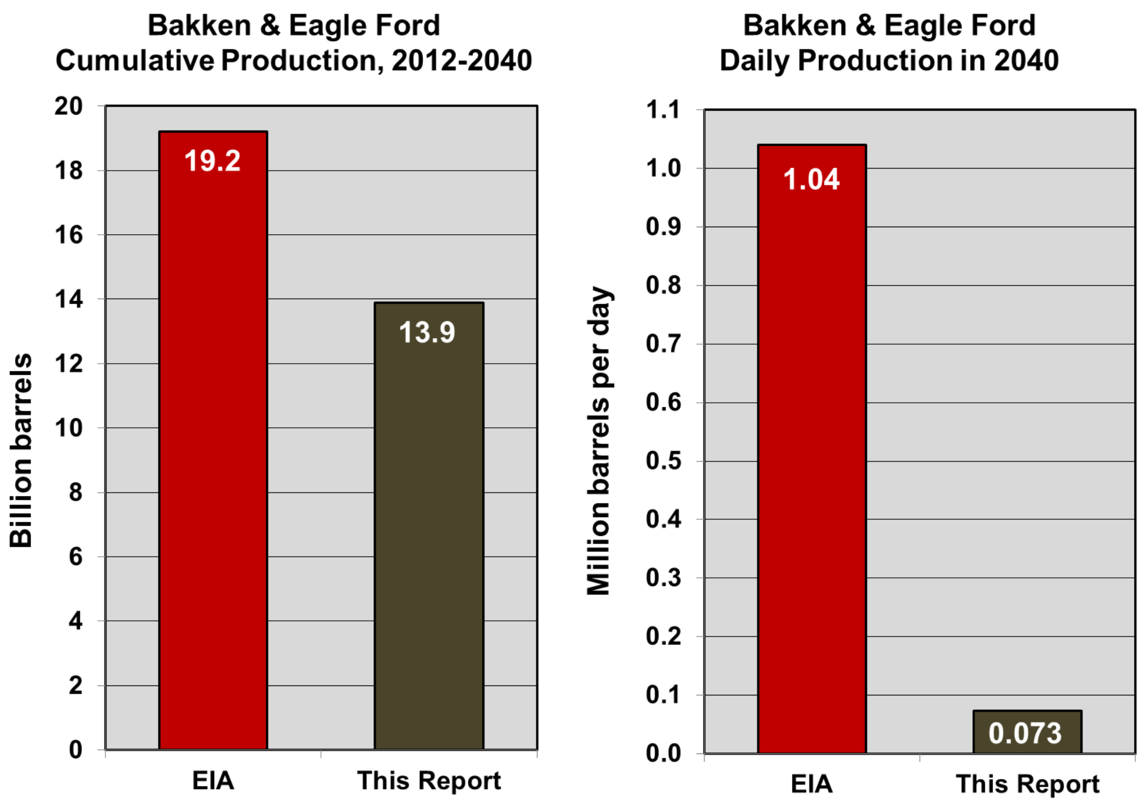


Figure 2-97. Bakken and Eagle Ford plays projected cumulative oil production from 2012 to 2040 and daily oil production in 2040, EIA projection[167] versus this report's projection.

The EIA's forecast strains credibility, given the known decline rates, well quality by area, available drilling locations, and the number of wells that would need to be drilled to make that happen. Given this report's "Most Likely" scenario estimate for the Bakken and Eagle Ford based on the analysis in this report, the remaining significant U.S. tight oil plays would need to produce 29.7 billion barrels of oil between 2012 and 2040 to meet the EIA's forecast—more than twice as much as the Bakken and Eagle Ford combined (see Figure 2-96). However, the EIA projects that these plays will produce just 23.5 billion barrels between 2014 and 2040. A more realistic best-case estimate, assuming capital inputs are not a constraint, is for these plays to produce about ten billion barrels over this period, which, coupled with 12.7 billion barrels from the Eagle Ford and Bakken, is just over half of the EIA's forecast by 2040—if everything goes right. Producing this much oil from these plays will require much higher oil prices than today's in the latter part of the 2014-2040 period. Most troubling from an energy security point of view is that much of the tight oil production will occur in the early years of this period, making supply ever more problematic later on.

[167] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

The consequences of getting it wrong on future tight oil production are immense. The EIA projects that the U.S. will be a significant oil importer in 2040 (Figure 2-2). Although the flush of tight oil production is likely to peak before 2020 and decline thereafter at much more rapid rates than projected by the EIA, there is increasing pressure by industry to allow crude oil exports.[168] The longer term geopolitical complications certain to arise given increased competition for available oil exports in a shrinking export market should be obvious. Rather than viewing tight oil as an unlimited bounty, it should be viewed for what it is—a short term reprieve from the inexorable decline in U.S. oil production. A sensible energy policy would be based on this prospect.

[168] IHS, "U.S. Crude Oil Export Decision," *Crude Oil Export Report*, 2014, http://www.ihs.com/info/0514/crude-oil.aspx.