2016 TIGHT OIL REALITY CHECK

REVISITING THE U.S. DEPARTMENT OF ENERGY PLAY-BY-PLAY FORECASTS THROUGH 2040 FROM ANNUAL ENERGY OUTLOOK 2016

J. DAVID HUGHES

post carbon institute

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Over the past decade, Hughes has researched, published and lectured widely on global energy and sustainability issues in North America and internationally. His work with Post Carbon Institute includes:

- a series of papers (2011) on the challenges of natural gas being a "bridge fuel" to renewables;
- *Drill, Baby, Drill* (2013), which considered prospects for unconventional resources in the U.S.;
- *Drilling California* (2013), which critically examined U.S. Energy Information Administration (EIA) estimates of technically recoverable tight oil in California's Monterey Shale, which the EIA claimed constituted two-thirds of U.S. tight oil (EIA subsequently reduced its resource estimate by 96%);
- *Drilling Deeper* (2014), which challenged the EIA's expectation of long-term domestic oil and natural gas abundance with an in-depth assessment of all drilling and production data from the major shale plays through mid-2014; and
- *Shale Gas Reality Check*, *Bakken Reality Check*, and *Eagle Ford Reality Check* (2015), updates to *Drilling Deeper* using data from the U.S. Department of Energy's *Annual Energy Outlook 2015*.

Separately from Post Carbon, Hughes authored *A Clear View of BC LNG* in 2015, which examined the issues surrounding a proposed massive scale-up of shale gas production in British Columbia for LNG export, and *Can Canada increase oil and gas production, build pipelines and meet its climate commitments?* in 2016, which examined the issues surrounding climate change and new export pipelines.

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About Post Carbon Institute

Post Carbon Institute's mission is to lead the transition to a more resilient, equitable, and sustainable world by providing individuals and communities with the resources needed to understand and respond to the interrelated environmental, energy, economic, and equity crises of the 21st century.

2016 Tight Oil Reality Check: Revisiting the U.S. Department of Energy Play-by-Play Forecasts through 2040 from Annual Energy Outlook 2016
By J. David Hughes. In association with Post Carbon Institute.

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1 Introduction

U.S. oil production was thought to be in permanent decline until the advent of tight oil a decade ago, which resulted in rapid growth of domestic oil production. This has led many in recent years to assume that a new, protracted golden age of domestic oil supplies was at hand. Since peaking in March 2015, however, total U.S. tight oil production was down 13% as of June 2016[1], and down 19% as of November 2016[2]—a decline in the production rate of more than one million barrels per day. Given that it is the major source of hope for growing or even maintaining U.S. oil production, a view to the future of tight oil is critical for establishing energy policy and avoiding unforeseen supply shortfalls.

Oil production forecasts by the Energy Information Administration (EIA) of the U.S. Department of Energy are published yearly in its *Annual Energy Outlook* (AEO). These are widely viewed by industry and government as the best available assessment of what to expect in the longer term, with the EIA's reference case typically viewed as the most likely scenario for future production. In the 2014 report *Drilling Deeper*[3], I reviewed the credibility of the EIA's *Annual Energy Outlook 2014* (AEO2014)[4] forecasts for the major U.S. tight oil and shale gas plays based on the fundamental geological characteristics of each play; I also developed alternate production forecasts for two major tight oil plays, the Bakken and Eagle Ford. In most plays the AEO2014 production projections were found to be highly optimistic when reviewed in the light of play fundamentals. In the case of the Bakken and Eagle Ford plays, the EIA overestimated recovery of oil through 2040 by 42% compared to my "Most Likely" drilling rate case.

The EIA recently released AEO2016[5] and kindly provided the underlying play-by-play production estimates for tight oil that make up its reference case. This report compares the forecasts in AEO2016 to the "Most Likely" case in *Drilling Deeper* and to the AEO2014 and AEO2015[6] forecasts; such comparisons are instructive in evaluating the volatility of EIA estimates for the same plays in forecasts separated by just one year, which reflects on their likely long-term accuracy. This report also assigns an "optimism bias" of the EIA's forecast for each play (summarized in Table 2, page 27).

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[1] Drillinginfo, October 2016. Historical production data used in this report's figures and tables are from the more comprehensive source Drillinginfo and are as of June 2016. Drillinginfo is a commercial database of well production data widely used by industry and government, including the EIA; see http://info.drillinginfo.com.

[2] Energy Information Administration, *Drilling Productivity Report* (October 2016), http://www.eia.gov/petroleum/drilling/archive/2016/10/. It should be noted that the EIA *Drilling Productivity Report* uses estimates for recent months.

[3] J. David Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts for a Lasting Tight Oil & Shale Gas Boom* (Santa Rosa, CA: Post Carbon Institute, 2014), http://www.postcarbon.org/drilling-deeper/.

[4] Energy Information Administration, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/archive/aeo14/.

[5] Energy Information Administration, *Annual Energy Outlook 2016*, http://www.eia.gov/forecasts/aeo/.

[6] Energy Information Administration, *Annual Energy Outlook 2015*, http://www.eia.gov/forecasts/archive/aeo15/.

1.1 KEY FUNDAMENTALS

Key fundamentals used in projecting future production of tight oil plays *in Drilling Deeper* were:

- **Rate of well production decline:** Tight oil plays have high well production decline rates, typically in the range of 75-85% in the first three years.
- **Rate of field production decline:** Tight oil plays have high field production declines, typically in the range of 30-45% per year, which must be replaced with more drilling to maintain production levels.
- **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 (and 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 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. The decline in oil prices starting in mid-2014 led oil producers to focus more on sweet spots, disproportionately depleting high-productivity drilling locations compared to the overall number of potential drilling locations in each play.
- **Number of potential wells:** Plays are limited in area and therefore have a finite number of locations that can be drilled. Once the locations run out, production goes into terminal decline.
- **Rate of drilling:** The rate of production is directly correlated with the rate of drilling, which is determined by the level of capital investment. The decline in oil price starting in mid-2014 resulted in a major decline in drilling rates in most plays, which resulted in production declines as intrinsic field decline overcame additions from new wells.

1.2 Overall Forecast Comparison to Past Years

How have the EIA's projections changed in 2016 compared to 2014 and 2015? Figure 1 compares the EIA's 2016 projections (AEO2016) to my "Most Likely" drilling rate forecasts in *Drilling Deeper* and to the EIA's AEO2014 and AEO2015 reference case projections.

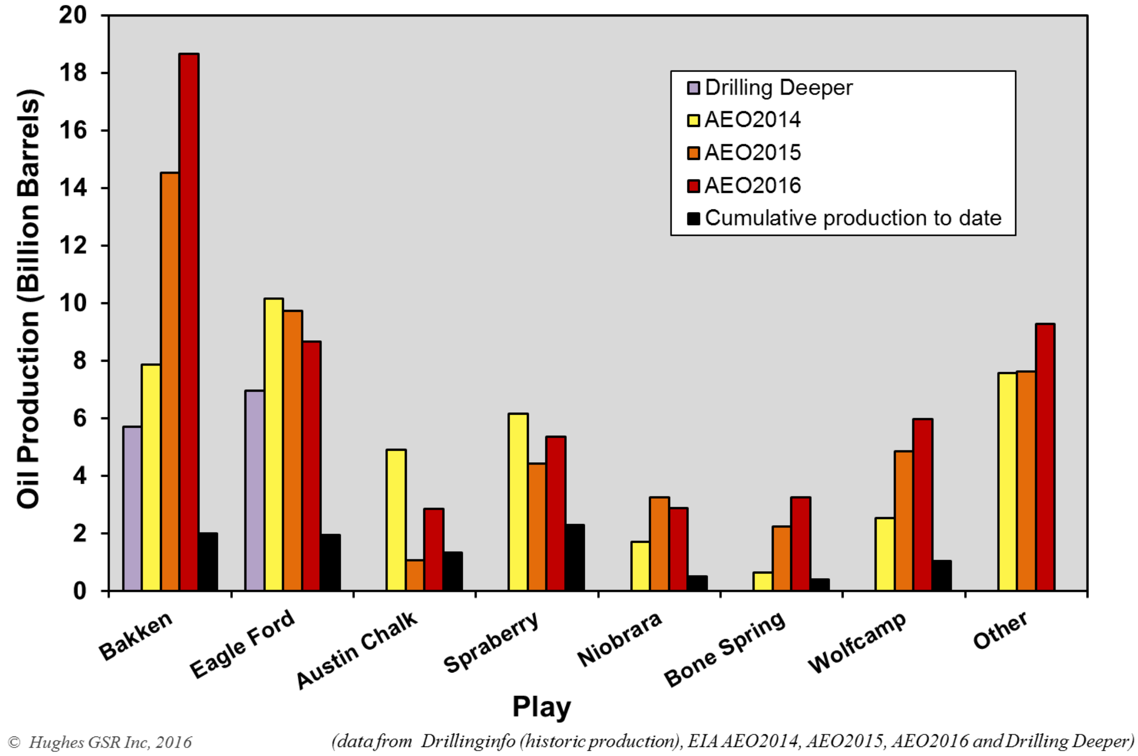

Figure 1. Cumulative tight oil production by play from 2014 to 2040 comparing AEO2014, AEO2015, AEO2016, and *Drilling Deeper* "Most Likely" projections, as well as cumulative production to date.

Significant increases in AEO2016 compared to AEO2015 occur in the Bakken, Austin Chalk, Spraberry, Bone Spring, Wolfcamp and "Other" plays, whereas the Eagle Ford and Niobrara have been downgraded. Overall production from 2014 to 2040 has increased by 8.5 billion barrels (or 19%) in AEO2016 compared to AEO2015, and by 14.7 billion barrels (or 37%) compared to AEO2014. Five of the seven plays assessed are below peak production. "Other" plays also peaked in July 2015.

Some general observations with respect to the assumptions and projections in the EIA's AEO2016 reference case:

- EIA assumes West Texas Intermediate (WTI) oil prices will remain low and will not exceed $100/barrel until 2031.
- EIA assumes tight oil production will continue growing and that U.S. oil production will reach an all-time high of 11.3 mbd in 2040, of which tight oil will be 63%. Overall tight oil production from 2014 to 2040 has increased by 19% in AEO2016 compared to AEO2015 and by 37% compared to AEO2014.
- The seven major plays analyzed in *Drilling Deeper*, which constituted 82% of AEO2014 projected tight oil production through 2040, have increased to 85% of the AEO2016 forecast. Production

from plays other than the major seven has increased by 22% between the AEO2015 and AEO2016.

- Forty-nine percent of tight oil production through 2040 is projected to come from the Bakken and Eagle Ford in AEO2016, compared to 51% in AEO2015—highlighting yet again that high quality tight oil plays are not ubiquitous.
- Considering that these forecasts are just 12 months apart, there is a lot of change in both recoveries through 2040 and the production profiles between projections, which raises questions about the robustness—or lack thereof—of the EIA's forecasting methods.

1.3 AEO2016 Production and Price Projections

Figure 2 illustrates the AEO2016 reference case for U.S. oil production by source, with price projections. Tight oil constitutes the largest source of supply, comprising 59% of cumulative production from 2014 to 2040, and 63% of 2040 production. Production from other major sources such as onshore and offshore conventional oil is projected to decline slightly, however overall U.S. production is projected to grow to an all-time high of 11.3 mbd in 2040. Prices are projected to remain below $100/barrel until 2031, and 2040 production is projected meet 65% of projected 2040 crude oil demand (up from 55% in AEO2015)—so, despite an aggressive production growth forecast the U.S. would still not become self-sufficient in oil.

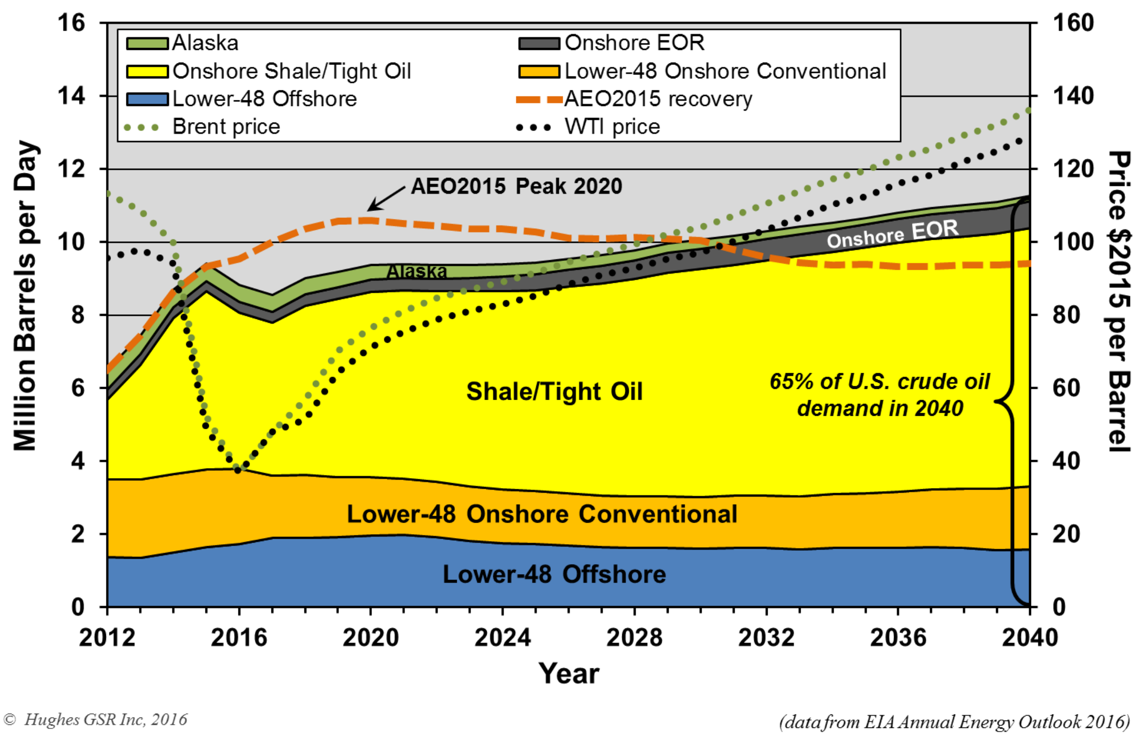

Figure 2. AEO2016 reference case forecast of oil production by source, 2012-2040.

Also shown is projected price (West Texas Intermediate and Brent in 2015 dollars per barrel) and the AEO2015 reference case forecast.

This is a very bullish forecast, especially given medium- and long-term projections of oil prices that are considerably below the levels that prevailed prior to mid-2014. Since the oil price downturn in mid-2014 there has been much industry rhetoric about lower break-even prices for tight oil as a result of greater rig efficiency, better technology, and reduced drilling costs. This is true to a certain extent and production has proven to be more resilient that many thought; however, production is falling in five of the seven major tight oil plays assessed herein and is being supported by short-term factors such as the inventory of "DUCs" (drilled but uncompleted wells) and by focusing drilling efforts on the core area of plays.

Figure 3 illustrates actual tight oil production from the seven major plays assessed in AEO2016 as well as "other" plays. All plays except the Spraberry and Wolfcamp in the Permian Basin are below peak production. The two largest plays, the Eagle Ford and the Bakken, which constituted 49% of tight oil production in June 2016, are down 31% and 18% from peak, respectively. Five of the major plays collectively peaked in March 2015, and were down 24% as of June 2016. Since the March 2015 peak, total tight oil production was down 13% as of June 2016[7], and down 19% as of November 2016.[8]

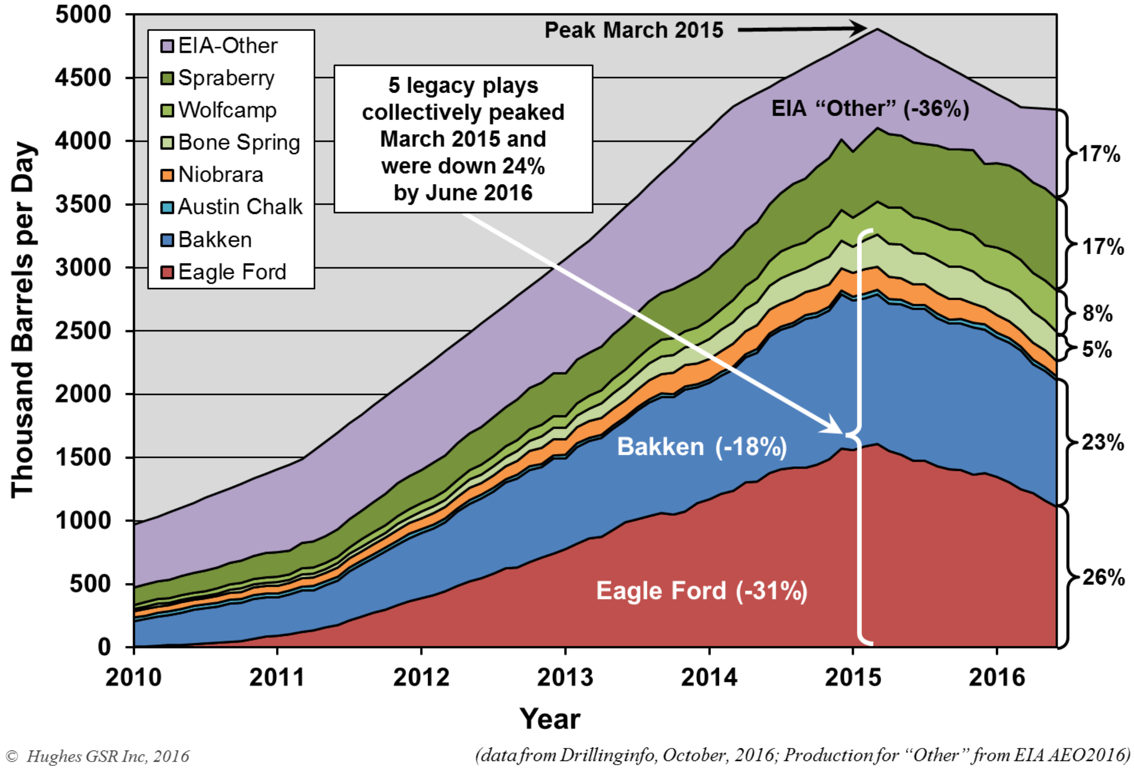

Figure 3. Tight oil production by play from 2010 through June 2016.

All plays except the Spraberry and Wolfcamp are below peak production. "Other" plays are down 15% (these include the Woodford and Monterey, which have relatively minor tight oil production).

[7] Drillinginfo, October 2016.

[8] Energy Information Administration, *Drilling Productivity Report* (October 2016), http://www.eia.gov/petroleum/drilling/archive/2016/10/.

With the drop in oil prices, companies adopted three strategies to lower break-even prices: apply better technology (longer horizontal laterals, higher volume injections of water and proppants, and more fracking stages); focus on drilling sweet spots; and pressure service companies to lower rates.[9] This resulted in lower break-even costs for production and considerable growth in average well productivity. Figure 4 illustrates average first-six-months well production by year for the major plays over the past five years. All plays except for the Eagle Ford (the largest tight oil producer) and the Niobrara exhibit significant improvements. This is due to a combination of drilling sweet spots (given that core areas are now well established in most plays) and better technology. The Bone Spring, Wolfcamp, and Spraberry plays, all within the Permian Basin, have exhibited the greatest improvement and are now similar in terms of well productivity to the Bakken core area—which makes industry's focus on the Permian understandable.

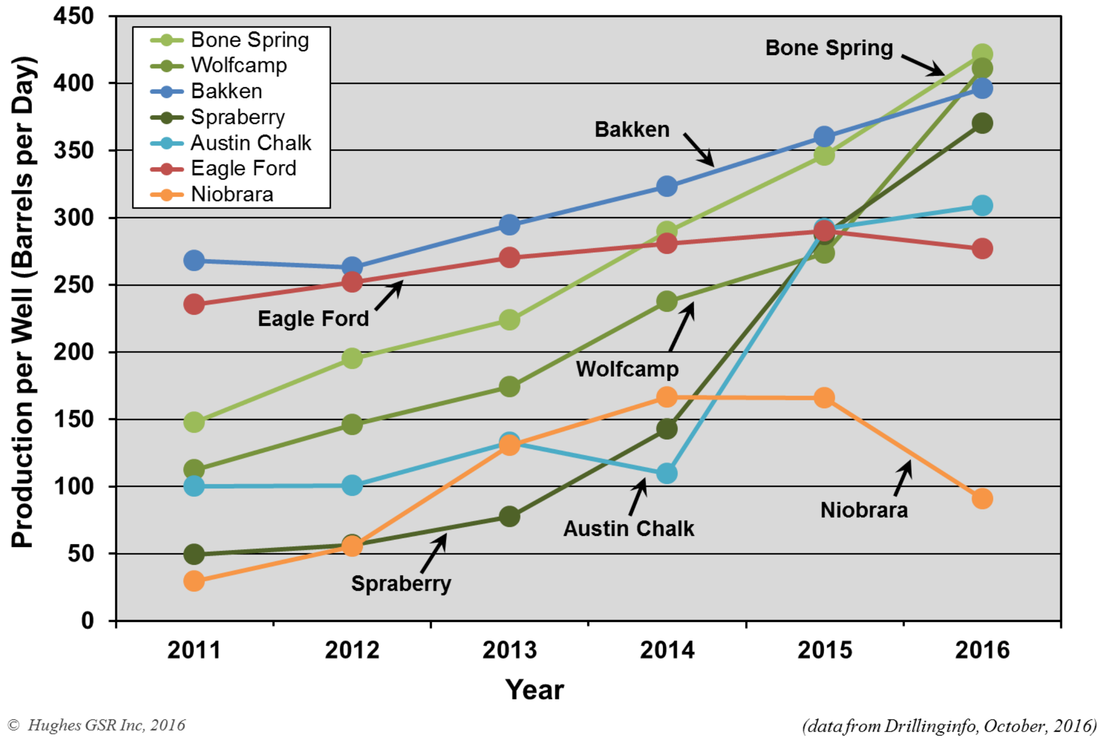

Figure 4. Average first-six-months well production by year for major tight oil plays, 2011-2016.

All plays have increased except for the Eagle Ford (the largest producer) and the Niobrara. These increases are due to better technology and the focus on drilling sweet spots.

The focus on better technology, however, will not necessarily increase overall recovery. Drilling sweet spots is thought to be nearly twice as important as better technology in reducing well costs according to IHS Markit.[10] Longer horizontal laterals with higher volume treatments drain more area and reduce the ultimate number of wells that can be drilled without interference. Hence better technology produces the resource sooner—and at potentially greater profit—but does not imply greater ultimate recovery. The consumption of the highest quality drilling locations during this period of low prices means that progressively higher prices will be needed, along with much higher drilling rates, to access the poorer

[9] Kurt Abraham, "Analyst touts industry's cost reductions in U.S. shale plays," *World Oil*, September 22, 2016, http://www.worldoil.com/news/2016/9/22/analyst-touts-industry-s-cost-reductions-in-us-shale-plays.

[10] Abraham, "Analyst touts industry's cost reductions in U.S. shale plays."

quality portions of shale plays and maintain production. Typically, sweet spots comprise less than 20% of total play area.

Given the relatively high field decline rates for tight oil of between 30% and 45% per year, the drilling rate of new wells to offset these declines is the key to maintaining or increasing production. Figure 5 illustrates the annual number of producing wells added to the major plays over the 2010 to 2016 period. The number of producing wells increases as more wells are drilled and decreases as older wells cease to produce. With the exception of the Bakken and Eagle Ford, other major plays have produced at some level for decades and are being redeveloped with better technology. Plays like the Austin Chalk and Niobrara have a negative growth rate in producing wells, despite more drilling, as older wells cease to produce. The number of producing wells added to the major plays peaked in January 2013 at an annual rate of 11,657. The impact of the downturn in oil price, (which began in mid-2014) on additions of producing wells is starkly evident. *Drilling Deeper*, which was published in October 2014 based on mid-2014 data, did not anticipate the severity of the oil price decline and the resultant radical downturn in drilling rate, and hence was too optimistic in its "Most Likely" scenario of future production as discussed in the following section.

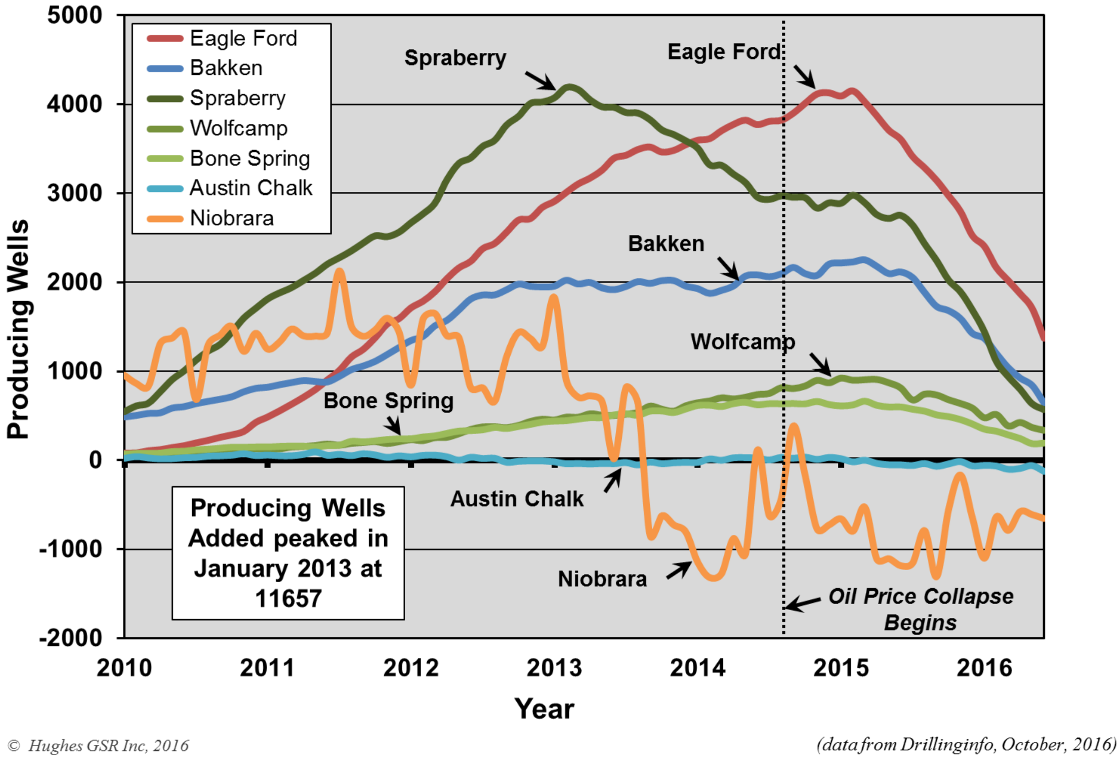

Figure 5. Annual net addition of new producing wells for major tight oil plays, 2010 through June 2016.

This is the sum of new producing wells added and wells that ceased production in the previous 12 months. Old plays like the Niobrara and Austin Chalk have negative well addition rates as more wells are being retired than are coming on production in recent years.

The question is: How much, and how quickly, can tight oil production ramp up with price increases? The EIA is very optimistic in its projections for most plays in AEO2016. Countering such optimism is the fact that industry has already drilled many of its best prospects, leaving lower productivity rock for later—which will require still higher prices to support the increasing number of lower productivity wells needed to maintain production, let alone grow it. The following look at the tight oil forecasts by individual play gives a better perspective on the credibility of the EIA projections.

2 Tight Oil Production by Play

Figure 6 illustrates the AEO2016 reference case forecast by tight oil play compared to AEO2014 and AEO2015. Half of projected 2014-2040 production comes from two plays, the Bakken and Eagle Ford, and the Bakken alone is responsible for nearly a third. Cumulative tight oil production in AEO2015 was 47.7 billion barrels, which is 6.2 billion barrels, or 15%, higher than AEO2014. Cumulative production in AEO2016 is 56.9 billion barrels, which is 9.2 billion barrels, or 19%, higher than AEO2015, and 37% higher than AEO2014. In AEO2015 tight oil production was projected to peak in 2020 at 5.6 mbd, but in AEO2016 continuous growth is projected through 2040, when production will be at 7.1 mbd.

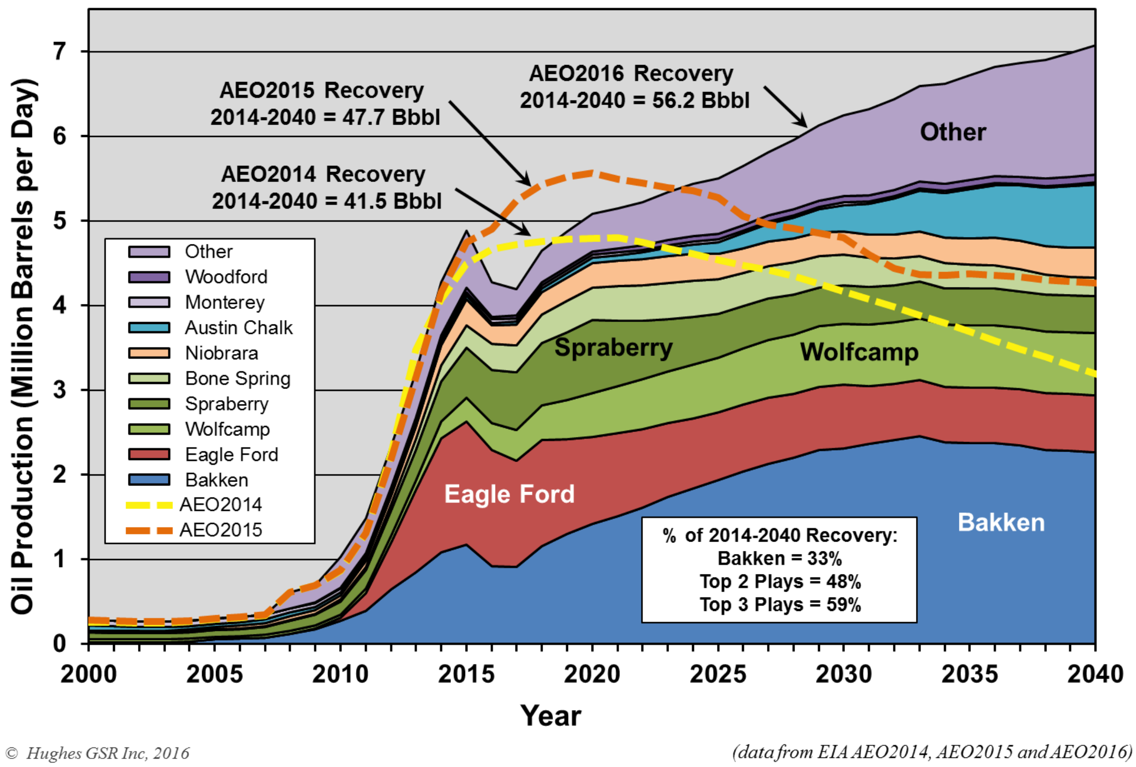

Figure 6. AEO2016 reference case forecast of oil production by tight oil play through 2040, compared to AEO2014 and AEO2015.

The EIA is even more bullish than last year, increasing cumulative 2014-2040 production by 19%, or 9.2 billion barrels, and projecting continued growth through 2040.

This is an extremely bullish forecast. Half of 2014-2040 production is forecast to come from just two plays, the Bakken and Eagle Ford, with an additional 25% from three Permian Basin plays—the Wolfcamp, Spraberry and Bone Spring. In total, according to this forecast, 74% of the "unproved technically recoverable tight oil resources" (as of January 1, 2013)[11] will be recovered by 2040; moreover, given that production is forecast to be at an all-time high in 2040, this implies that all remaining unproved resources will be recovered shortly thereafter. As shown in Table 1, between 52% and 114% or more of the unproved resources for the major plays are forecast to be produced by 2040, and for the top two plays, the Bakken and Eagle Ford, recovery is projected to be 84% and 88%, respectively. Assuming recovery

[11] Energy Information Administration, "Oil and Gas Supply Module," *Assumptions to the Annual Energy Outlook 2015*, September 2015, https://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

factors this high is extremely optimistic, given that these "unproved resources" are just probabilistic estimates that may or may not exist; and even if they do exist they are not necessarily "economically" recoverable—a key criterion for "reserve" estimates used to value a company's holdings on the stock market. The credibility of the individual play-level EIA reference case forecasts is further assessed below.

Play	Unproved resources as of January 1, 2013 (Bbbl)	Oil recovery 2013-2040 (Bbbl)	% of unproved resource recovered by 2040
Bakken	22.70	18.96	83.5%
Spraberry	10.60	5.48	51.7%
Eagle Ford	10.30	9.02	87.6%
Wolfcamp	6.10	6.02	98.7%
Austin Chalk	5.50	2.87	52.1%
Bone Spring	2.90	3.30	113.8%
Monterey	0.60	0.32	54.1%
Niobrara	0.40	2.94	735.0%
Woodford	0.30	0.64	211.8%
Other	19.70	8.55	43.4%
Total	**78.20**	**58.10**	**74.3%**

Table 1. Unproved technically recoverable tight oil resources as of January 1, 2013, compared to forecast production by play from 2013 to 2040 in the EIA AEO2016 reference case.[12]

Note that the figures used in this table are from EIA's analysis of unproved technical recoverable resources, which uses 2013 as the starting year; elsewhere in this report, however, production forecast figures use 2014 as the starting year consistent with AEO2016.

[12] Energy Information Administration, "Oil and Gas Supply Module."

2.1 BAKKEN PLAY

Figure 7 illustrates the AEO2016 reference case forecast for the Bakken compared to AEO2014, AEO2015 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2016, the Bakken is forecast to contribute 33% of all tight oil production from 2014 to 2040, and 32% of 2040 production.

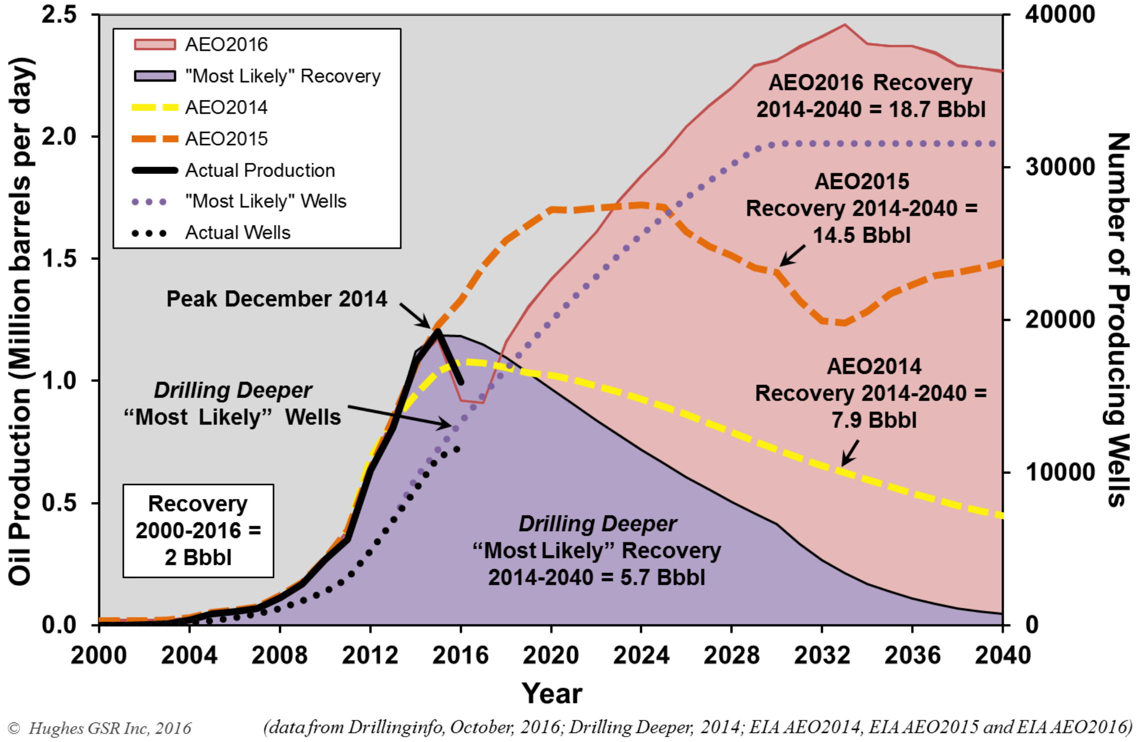

Figure 7. Bakken Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

Also shown are actual production, actual cumulative producing wells, and the cumulative wells that would have to be drilled for the "Most Likely" drilling rate in *Drilling Deeper*. Cumulative production through mid-2016 was 2 billion barrels. AEO2016 estimates cumulative recovery over the 2014-2040 period of 18.7 billion barrels, compared to 5.7 billion barrels in *Drilling Deeper*.

The EIA has increased 2014-2040 recovery from the Bakken in AEO2016 to 18.7 billion barrels, which is 4.1 billion barrels (or 28%) higher than AEO2015 and 10.8 billion barrels (or 137%) higher than AEO2014. This is more than double the recent USGS assessment[13] of undiscovered technically recoverable resources from the Bakken (including Three Forks) of 7.4 billion barrels (the AEO2016 forecast would see 19.7 billion barrels recovered between 2000 and 2040). In contrast, my "Most Likely" forecast in *Drilling Deeper* for 2000-2040 recovery, at 6.8 billion barrels, is comparable to the USGS assessment.

[13] Stephanie Gaswirth, et al., *Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota*, U.S. Geological Survey, 2013, http://pubs.usgs.gov/fs/2013/3013/.

Bakken production is concentrated in four counties in North Dakota and one county in Montana; the core counties of the play are illustrated in Figure 8. Together these counties accounted for 92% of Bakken oil production as of mid-2016 from both the Bakken and underlying Three Forks reservoirs. They occupy a total of 10,730 square miles, although not all parts of each county are prospective. Drilling has occurred outside of these counties but such wells are generally much less productive, hence the focus on the core area.

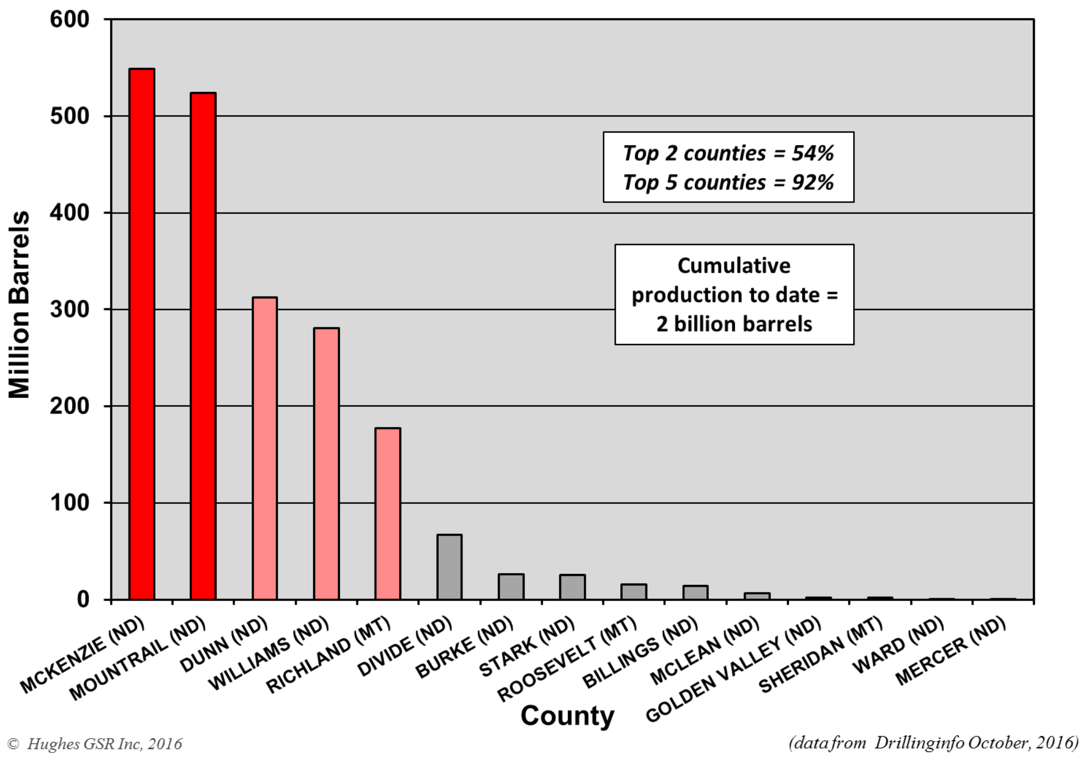

Figure 8. Bakken Play cumulative oil production by county through mid-2016.

The EIA assigns 63% of its estimate of "unproved technically recoverable resources" to the Three Forks reservoir inferred to underlie an area of over 28,000 square miles, a large portion of which has no producing wells.[14] The EIA projects that this area could be drilled at a density of 4 wells per square mile, for a total of 112,000 wells. Notwithstanding these major uncertainties, the EIA projects that 84% of all unproved resources in the Bakken and Three Forks will be produced by 2040 at relatively low prices. The fact that the EIA's projection exits 2040 at a production level of over 2 mbd—more than double current production—suggests the remaining 17% would be recovered very soon thereafter, unless there are vast additional as yet unknown recoverable resources. This strains credibility to the limit, and the EIA's Bakken estimate is therefore assigned an "extremely high" optimism bias.

Some observations:

- There is no apparent justification for more than doubling the expected recovery from the Bakken through 2040 from the EIA's AEO2014 projection. The AEO2016 projection is extremely optimistic and highly unlikely to be realized.

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[14] Energy Information Administration, "Oil and Gas Supply Module."

- The only way production could keep growing to more than double current production is with a massive ramp up in drilling to rates of at least double the maximum in the Bakken to date, which topped out at a little over 2000 wells per year (Figure 5). Coupled with declining well quality as sweet spots are exhausted, drilling rates would likely need to be even higher, requiring much higher prices than the EIA forecasts—assuming the recoverable resources even exist, which is unlikely.

- Drilling rates in the *Drilling Deeper* "Most Likely" forecast, which projected nearly a 3-fold increase over the current 11,600 producing wells to a maximum of 31,600, would see remaining drilling locations run out by 2029. The production projections in AEO2016 would see locations run out much sooner, unless there are vastly more locations than assumed. Well interference is already evident in the former top producing county, Mountrail,[15] indicating that available locations there are running out; and drilling is now concentrated in the remaining three top counties in North Dakota. The assumption that Bakken production will grow to more than double the current level and exit 2040 at more than 2 mbd lacks credibility, based on fundamentals. A rough calculation of the number of wells required to do this, assuming locations existed, would be 120,000 by 2040, at a cost of $720 billion assuming $6 million per well.

- The drop in rig counts in the Bakken (28 in October 2016 vs. 198 in October 2014) has not impacted well addition rates as much as it might have due to greater rig efficiency and the large number of drilled but uncompleted wells (DUCs), some of which are now coming on line. This is a temporary buffer, however, and Bakken production peaked in December 2014. The decline in the Bakken could be stemmed or temporarily reversed with a ramp up in drilling rates, but the projections in AEO2016 are extremely unlikely to be realized, hence the "extremely high" optimistic bias rating.

- Given that the Bakken is one-third of the 2014-2040 tight oil production in the EIA's reference case projection, this serious overestimation significantly affects the entire outlook.

[15] J. David Hughes, *Bakken Reality Check: The Nation's Number Two Tight Oil Play After a Year of Low Oil Prices*, (Post Carbon Institute, October 2015), http://www.postcarbon.org/publications/bakken-reality-check/.

2.2 EAGLE FORD PLAY

Figure 9 illustrates the AEO2016 reference case forecast for the Eagle Ford compared to AEO2014, AEO2015 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2016, the Eagle Ford is forecast to contribute 15% of all tight oil production from 2014 to 2040, and 9.5% of 2040 production.

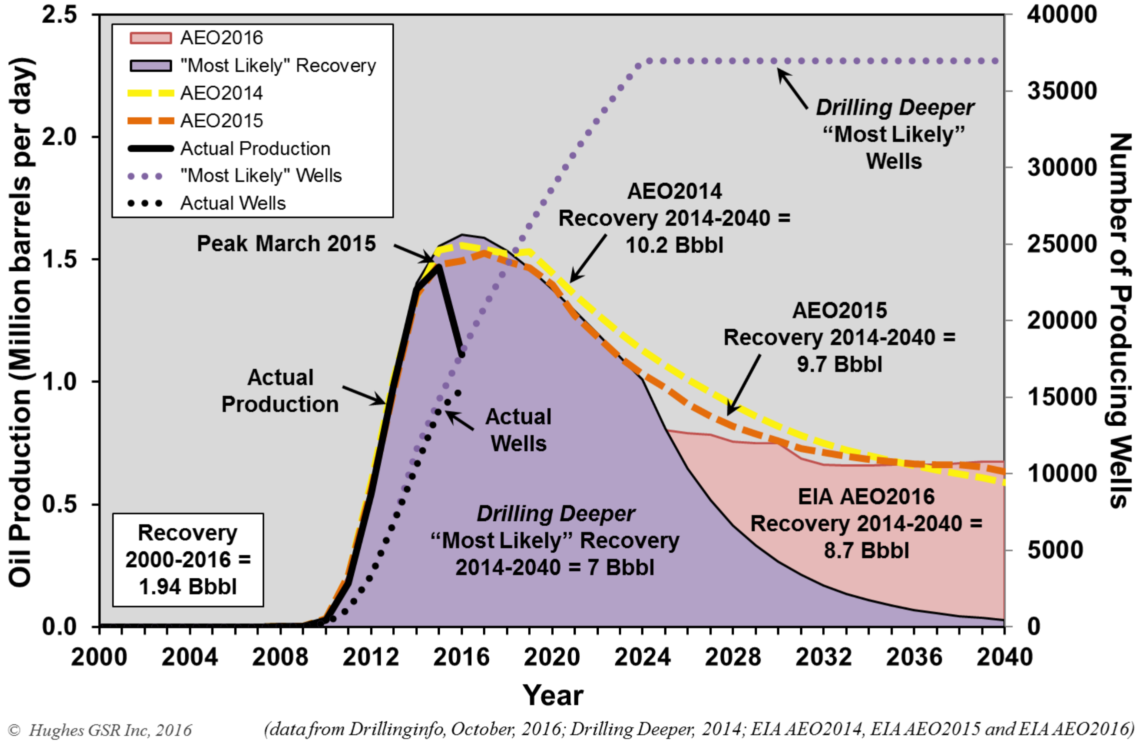

Figure 9. Eagle Ford Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

Also shown are actual production, actual cumulative producing wells, and the cumulative wells that would have to be drilled for the "Most Likely" drilling rate. Cumulative production through mid-2016 was 1.94 billion barrels. AEO2016 estimates cumulative recovery over the 2014-2040 period of 8.7 billion barrels, compared to 7 billion barrels in *Drilling Deeper*.

The AEO2016 projection reflects the dramatic downturn in producing well additions (see Figure 5) which was not anticipated in my "Most Likely" forecast in *Drilling Deeper*. The Eagle Ford peaked at 1.61 mbd in March 2015 at the level forecast but several months sooner than I had projected. AEO2016 reduced projected 2014-2040 production by 11%, or one billion barrels, from AEO2015 and by 15% from AEO2014. AEO2016 is 24% higher than my estimate of 7 billion barrels in *Drilling Deeper*, compared to 46% higher in AEO2014. The EIA's re-profiling of production in AEO2016 to reflect higher production at later dates is reasonable given that the downturn in drilling has left more locations to be drilled later. Compared to the other tight oil plays the EIA has done a considerably more thorough analysis of the Eagle Ford.[16]

Relatively high-productivity counties are more widespread in the Eagle Ford than in the Bakken, hence there are more drilling locations available. Figure 10 illustrates the distribution of cumulative oil production by county. Although half of production has come from three counties, nine counties account

[16] Dana Van Wagener, "U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level", *Annual Energy Outlook 2014*, April 7, 2014, http://www.eia.gov/forecasts/archive/aeo14/section_issues.cfm#tight_oil.

for 94% of production in the Eagle Ford, versus five counties counting for 92% of production in the Bakken.

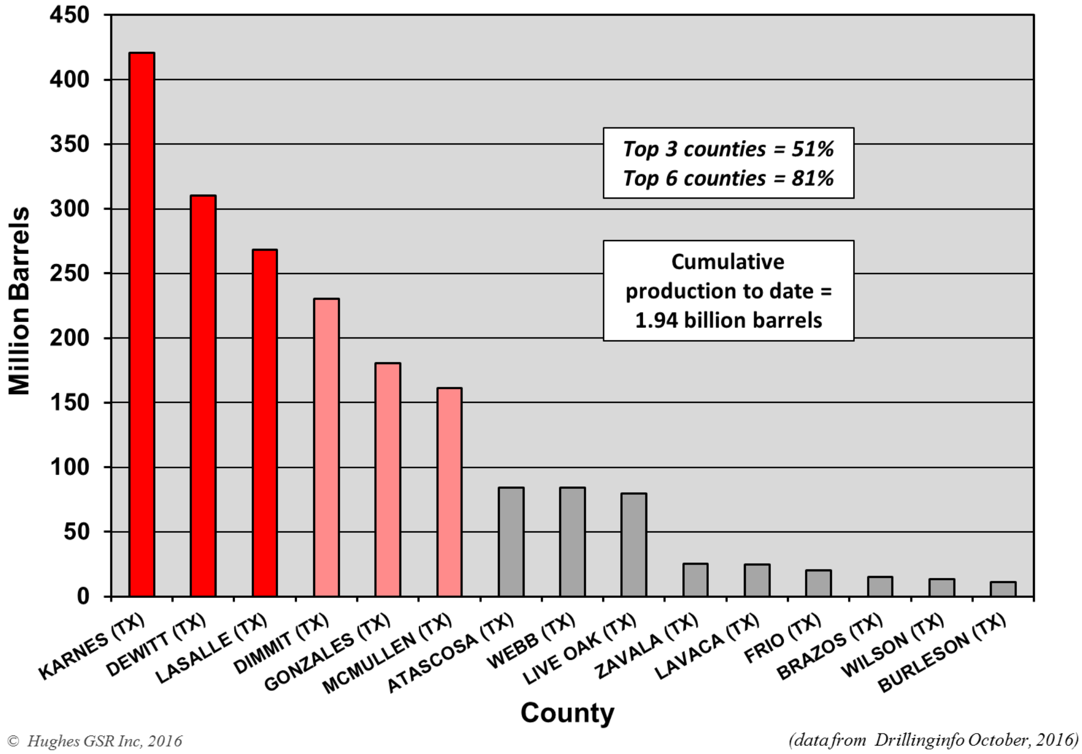

Figure 10. Eagle Ford Play cumulative oil production by county through mid-2016.

Some observations:

- The EIA's AEO2016 Eagle Ford production projection is much more reasonable than its Bakken forecast and reflects what has happened with the dramatic production drop due to declining drilling rates in the current low oil price environment.
- The drop in rig counts in the Eagle Ford (35 in October 2016 vs. 218 in October 2014) has caused a 66% drop in the rate of addition of producing wells (Figure 5), hence the drop in production. Drilling but uncompleted wells (DUCs) have likely reduced the amount of production decline compared to what it might have been without them.
- My "Most Likely" forecast in *Drilling Deeper* projected a 3-fold increase in the number of producing wells over current levels before drilling locations ran out in 2024. The drastic reduction in the drilling rate to well below the rate I had projected in *Drilling Deeper* will extend drilling for several years beyond 2024 and hence increase production rates somewhat over what I had forecast in later years (but reduce production in the short and medium term). The AEO2016 projection is reasonable out to 2030, when available drilling locations are likely to run out, and field decline will steepen. The flattening of the production decline post-2030 in AEO2016, and the suggestion that production will exit 2040 at .67 mbd, would require far more drilling locations than are estimated to be available; it would also require recovering 88% of the EIA's estimate of "unproved technically recoverable resources" by 2040 (see Table 1). Nonetheless the overall optimism bias of AEO2016 is an improvement over AEO2015, and must be rated as "moderate", down from "high" in AEO2015.

2.3 PERMIAN BASIN

The Permian Basin has been producing oil for over a century and is one of the most productive basins in the U.S. With the advent of horizontal drilling and hydraulic fracturing, many of the older plays here are being redeveloped. The Permian Basin has attracted a lot of drilling attention as drilling in other plays like the Bakken and Eagle Ford has declined. AEO2016 provides play-level forecasts for three major Permian Basin plays—the Wolfcamp, Spraberry, and Bone Spring—which collectively contain 65% of EIA's estimate of "unproved technically recoverable resources" in the Permian Basin.

2.3.1 Wolfcamp Play

Figure 11 illustrates the AEO2016 reference case forecast for the Wolfcamp compared to AEO2014 and AEO2015. In AEO2016, the Wolfcamp, which is one of the largest plays in the Permian Basin, is forecast to contribute 10.5% of all tight oil production from 2014 to 2040, and 10.3% of 2040 production.

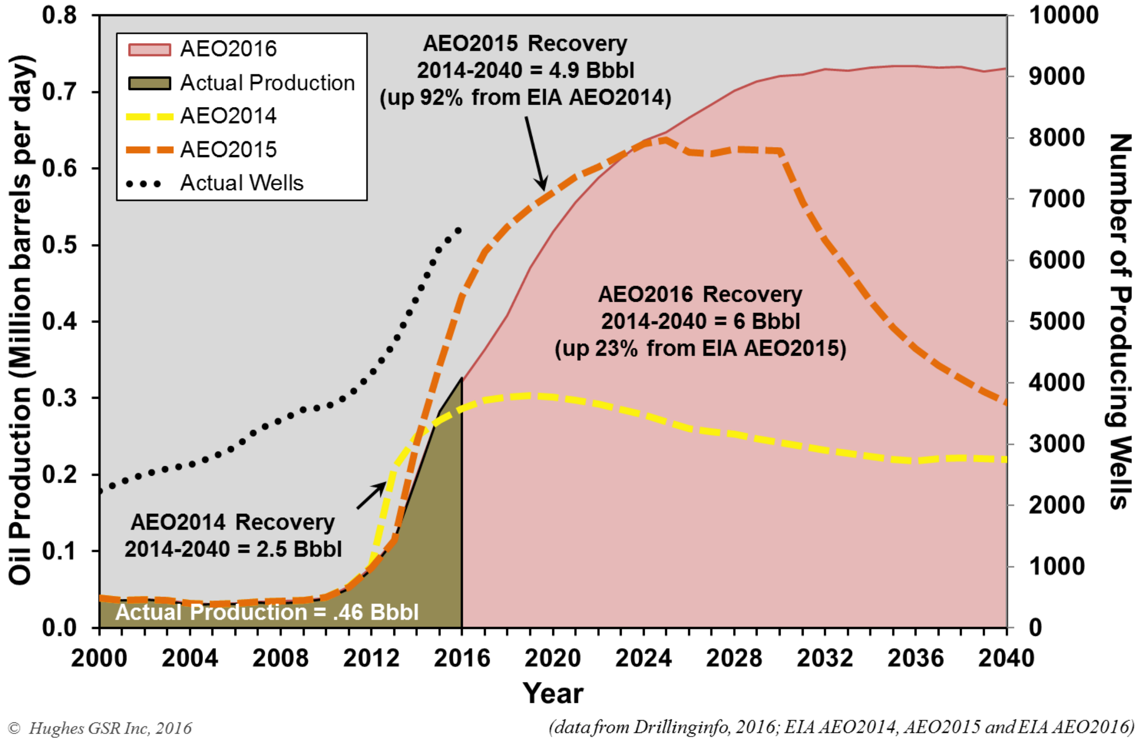

Figure 11. Wolfcamp Play production for AEO2016 compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative number of producing wells and cumulative production from 2000 to mid-2016 (.46 billion barrels).

The AEO2016 projection of six billion barrels over the 2014-2040 period is up 23% from AEO2015 and up 136% from AEO2014. The Wolfcamp is an old play being redeveloped with the latest technology, and more than 13,600 wells have been drilled there since the 1950s. The play has received a lot of drilling attention recently and the number of producing wells has doubled since 2008 to 6,543 as of mid-2016. Production has been growing and in June 2016 was at .33 mbd, which is less than half of the projected maximum production in AEO2016. If the EIA's AEO2016 forecast came to fruition, 98.7% of the EIA's estimate of "unproved technically recoverable resources" would be produced by 2040, with production in

2040 still at maximum levels. Of course, oil production in a play will typically peak and then decline gradually, rather than peak and then drop off a cliff; which is to say, the EIA apparently assumes without any apparent justification that considerable unknown resources—in addition to projected unproved technical recoverable resources—exist in the Wolfcamp that would allow production to decline for years if not decades to come after 2040.

The recent USGS announcement of 20 billion barrels of "undiscovered" technically recoverable resources in the Wolfcamp has attracted a lot of attention. These resources, as the USGS makes clear, have a roughly 50% probability of existing and are not necessarily economically recoverable. Based on USGS assumptions, they would cost some $1.4 trillion dollars to recover, or $500 billion more than they are worth at $45 per barrel.[17]

Last year I rated the EIA's AEO2015 forecast for the Wolfcamp as having a "very high" optimism bias given that it assumed 80% of the unproved resources would be recovered by 2040. The AEO2016 must be rated as having an "extremely high" optimism bias, given that nearly all of the EIA's estimate of unproved resources are projected to be recovered by 2040, with production to remain at all-time highs in 2040.

Some observations:

- Permian Basin plays like the Wolfcamp are not typical "shale" plays like the Bakken and Eagle Ford. They have produced much oil over many decades utilizing conventional production techniques and are now benefiting from redevelopment with horizontal drilling and hydraulic fracturing. Production from the Wolfcamp is thus from a mix of "conventional" and "unconventional" sources. *Drilling Deeper* did not develop a range of production projections for these older plays but did evaluate the fundamentals of each play for assessment of the EIA projections.
- The Wolfcamp is one of the best Permian Basin plays and appears to have significant upside. It has produced just over a billion barrels since the 1950s and has seen extensive recent drilling. However, AEO2016's assumptions that production can more than double by 2028, and produce another 6 billion barrels by 2040, is an extremely aggressive forecast, given play fundamentals; hence the "extremely high" optimism bias rating.
- The drop in rig counts in the Permian Basin (169 in October 2016 vs. 568 in November 2014) will undoubtedly affect Wolfcamp drilling rates (rig counts are not disaggregated at the play level in the Permian Basin), although production is currently still rising. AEO2016 projections that production can more than double and exit 2040 at all-time production highs after producing 6 billion barrels of oil, however, are highly unlikely to happen.

[17] Richard Heinberg and J. David Hughes, "Howling at the USGS's Wolfcamp Announcement," Post Carbon Institute, December 1, 2016; http://www.postcarbon.org/howling-at-the-usgss-wolfcamp-announcement/.

2.3.2 Spraberry Play

Figure 12 illustrates the AEO2016 reference case forecast for the Spraberry compared to AEO2014 and AEO2015. In AEO2016, the Spraberry, which is one of the largest plays in the Permian Basin (and includes the Trend area), is forecast to contribute 9.4% of all tight oil production from 2014 to 2040, and 6.2% of 2040 production.

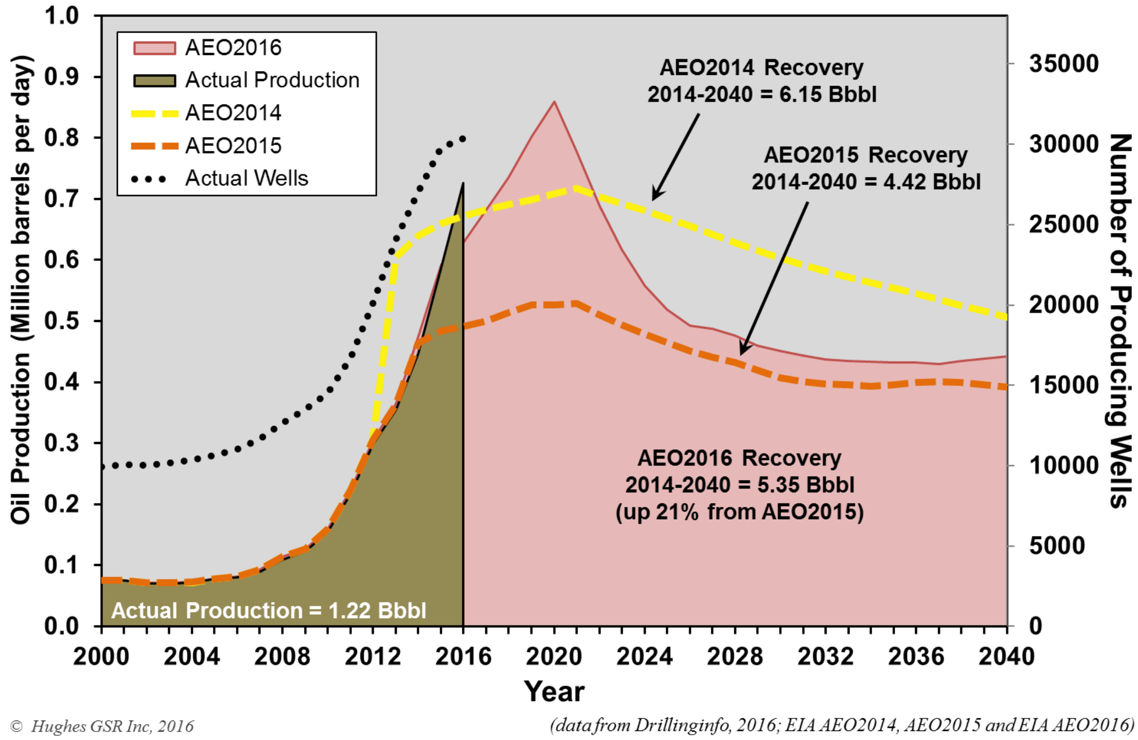

Figure 12. Spraberry Play production for AEO2016 compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative number of producing wells and cumulative production from 2000 to mid-2016 (1.22 billion barrels).

The AEO2016 projection of 5.35 billion barrels over the 2014-2040 period is up 21% from AEO2015 and down 13% from AEO2014. The Spraberry is an old play being redeveloped with the latest technology, and more than 42,600 wells have been drilled there since the 1940s. The play has received a lot of drilling attention recently and the number of producing wells has doubled since 2010 to 30,356 as of mid-2016. Production has been growing rapidly and in June 2016, was at .73 mbd, which is within 18% of the 2020 peak projected in AEO2016. If the EIA's AEO2016 forecast came to fruition, 52% of the EIA's estimate of "unproved technically recoverable resources" would be produced by 2040, with production declining after the 2020 peak. I rated the EIA's AEO2015 forecast as having a "moderate" optimism bias and, given developments in the meantime, the AEO2016 forecast must also be rated as having a "moderate" optimism bias. The portion of the forecast that is overly optimistic is flat-lining production after 2028 given the likely decline in per-well productivity as the sweet spots become saturated with wells.

Some observations:

- The Spraberry is not a typical "shale" play like the Bakken and Eagle Ford. It has produced 2.3 billion barrels of oil over many decades utilizing conventional production techniques and is now benefiting from redevelopment with horizontal drilling and hydraulic fracturing. Production from the Spraberry is thus from a mix of “conventional” and “unconventional” sources. *Drilling Deeper* did not develop a range of production projections for this play but did evaluate the fundamentals for assessment of the EIA projections.

- The Spraberry is one of the best Permian Basin plays and one of its largest producers, although it appears to be fairly close to peak production. It has seen very extensive drilling recently. AEO2016’s assumption that production can grow somewhat to a 2020 peak appears reasonable. The assumption that production will flatline in 2028 after declining from a 2020 peak, and exit 2040 at .45 mbd after producing an additional 5.35 billion barrels, is optimistic, however; hence the overall rating of a “moderate” optimism bias.

- The drop in rig counts in the Permian Basin (169 in October 2016 vs. 568 in November 2014) will undoubtedly affect the Spraberry drilling rate (rig counts are not disaggregated at the play level in the Permian Basin) although production is currently still rising.

2.3.3 Bone Spring Play

Figure 13 illustrates the AEO2016 reference case forecast for the Bone Spring play (termed Avalon/Bone Spring by the EIA) compared to AEO2014 and AEO2015. In AEO2016, the Bone Spring—which ranks third in the Permian Basin behind the Wolfcamp and Spraberry in the EIA's projections—is forecast to contribute 5.3% of all tight oil production from 2014 to 2040, and 3% of 2040 production.

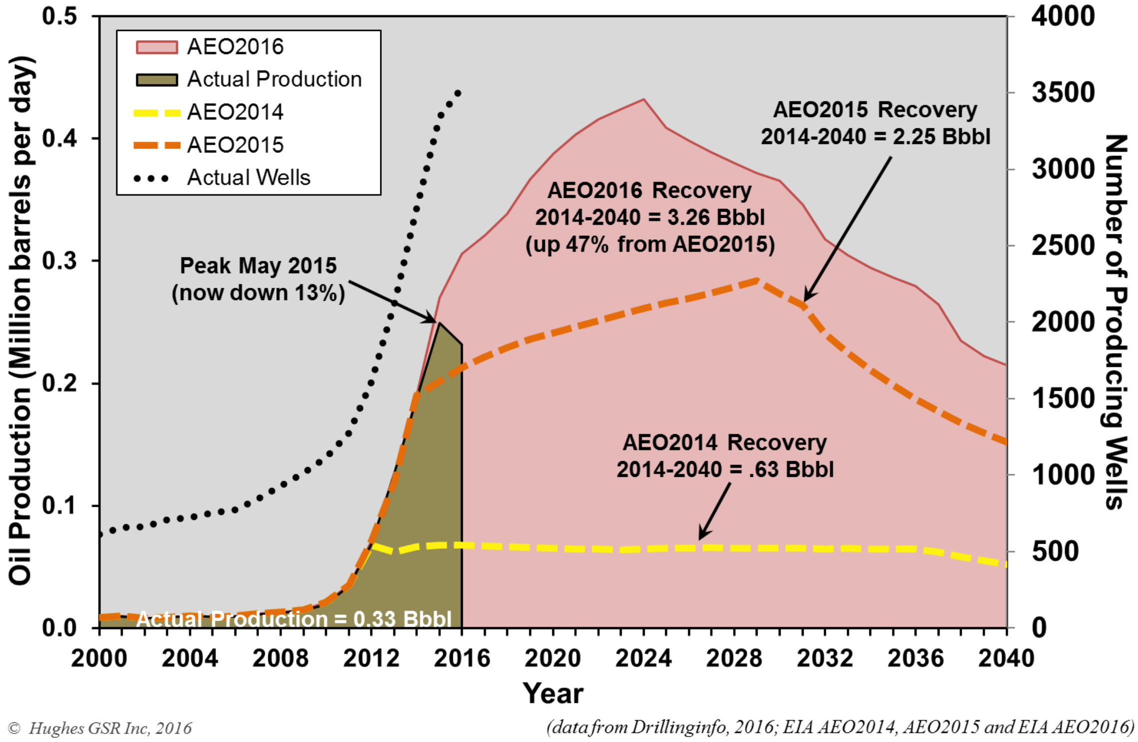

Figure 13. Bone Spring Play production for AEO2016 compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative number of producing wells and cumulative production from 2000 through mid-2016 (.33 billion barrels).

The AEO2016 projection of 3.26 billion barrels over the 2014-2040 period is up 45% from AEO2015 and up 414% from AEO2014. Like the Wolfcamp and Spraberry Permian Basin plays, the Bone Spring is an old play being redeveloped with the latest technology, and more than 7,300 wells have been drilled there since the 1970s. The play has received a lot of drilling attention recently and the number of producing wells has more than tripled since 2009 to 3,535 as of mid-2016. After rapid production growth from 2010 the play peaked in May 2015 and is now down 13%, at .23 mbd. If the EIA's AEO2016 forecast came to fruition, 114% of the EIA's estimate of "unproved technically recoverable resources" would be produced by 2040, with production declining after the 2024 peak. I rated the EIA's AEO2015 forecast as having a "moderate" optimism bias; however, given the fact that the play has already peaked, that it is primarily focused in two counties, and that the EIA is projecting to recover more unproved resources than are known to exist, the optimism bias of the AEO2016 projection is rated at "very high".

Some observations:

- The Bone Spring is not a typical "shale" play like the Bakken and Eagle Ford. It has produced 400 million barrels of oil over several decades, initially utilizing conventional production techniques and now benefiting from redevelopment with horizontal drilling and hydraulic fracturing.

Production from the Bone Spring is thus from a mix of “conventional” and “unconventional” sources. *Drilling Deeper* did not develop a range of production projections for this play but did evaluate the fundamentals for assessment of the EIA projections.

- The Bone Spring production is concentrated in two counties, which account for 85% of production to date, and hence is relatively small compared to the much larger areas of significant production in the Wolfcamp and Spraberry Permian Basin plays. Significantly higher drilling rates, given higher prices, might temporarily reverse the current decline but the EIA’s outlook is highly unlikely to be realized; hence the “very high” optimistic bias rating.
- The drop in rig counts in the Permian Basin (169 in October 2016 vs. 568 in November 2014) has reduced the drilling rate in the Bone Spring and resulted in its peak and decline.

2.4 NIOBRARA PLAY

Figure 14 illustrates the AEO2016 reference case forecast for the Niobrara play compared to AEO2014 and AEO2015. In AEO2016. The Niobrara is projected to contribute 5% of all tight oil production from 2014 to 2040, and 5.1% of 2040 production. The Niobrara is one of the largest plays in the Denver-Julesburg (D-J) Basin, although most production has been from the Wattenburg Field in Weld County of Colorado.

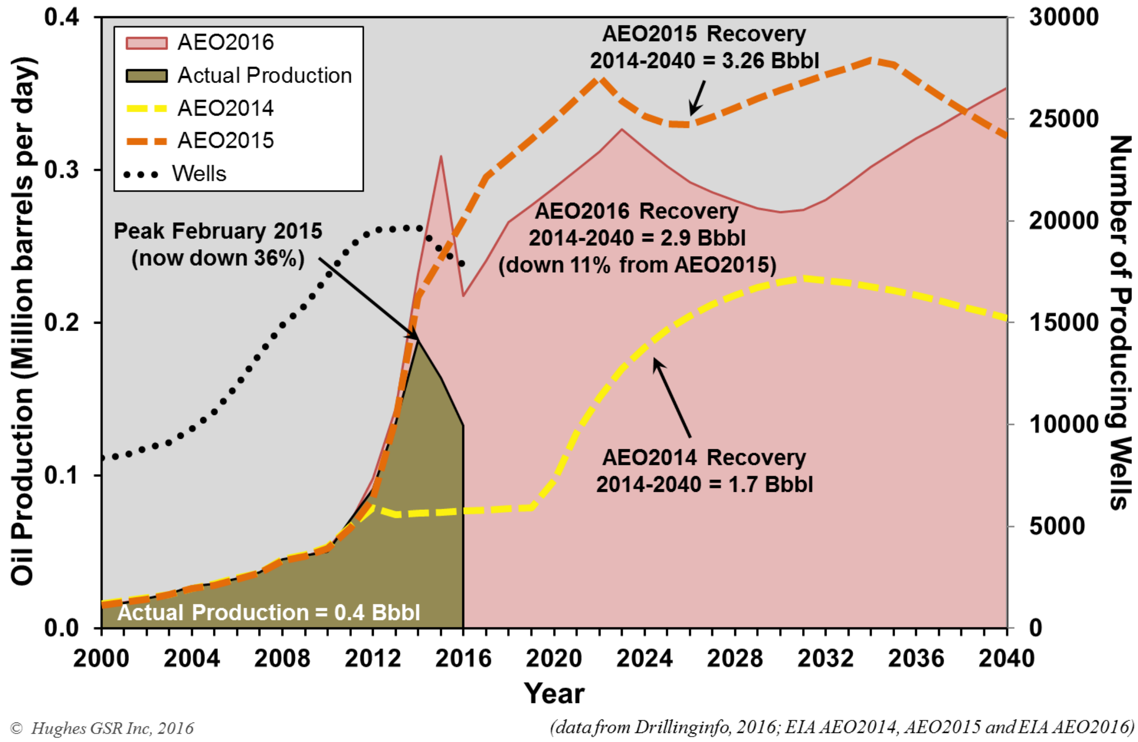

Figure 14. Niobrara Play production for AEO2016 compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative number of producing wells and cumulative production from 2000 to mid-2016 (.4 billion barrels).

The AEO2016 projection of 2.9 billion barrels over the 2014-2040 period is down 11% from AEO2015 and up 71% from AEO2014. The Niobrara is an old play being redeveloped with the latest technology, and more than 33,100 wells have been drilled there since the 1950s. The play has received a lot of drilling attention recently and the number of producing wells has doubled since 2005 to a peak of 20,694 in 2014, but has since declined to 17,880 (as of mid-2016) as older wells are taken out of production. After rapid production growth from 2010 the play peaked in February 2015 and is now down 36%, at .12 mbd.

If the EIA's AEO2016 forecast came to fruition, 735% of the EIA's estimate of "unproved technically recoverable resources" would be produced by 2040, with production exiting 2040 at an all-time high. I rated the EIA's AEO2015 forecast as having an "extremely high" optimism bias. This rating has to be maintained for AEO2016, given the maturity of the play, the generally lower productivity of wells compared to the Bakken or Eagle Ford, and the fact that the EIA is counting on producing far more oil than known unproved technically recoverable resources. Furthermore, average well productivity is declining—indicating some of the best areas have been drilled out—as shown in Figure 4.

Some observations:

- The Niobrara is not a typical “shale” play like the Bakken and Eagle Ford. It has produced 524 million barrels of oil over several decades, initially utilizing conventional production techniques and now benefiting from redevelopment with horizontal drilling and hydraulic fracturing. Production from the Niobrara is thus from a mix of “conventional” and “unconventional” sources. *Drilling Deeper* did not develop a range of production projections for this play but did evaluate the fundamentals for assessment of the EIA projections.

- Niobrara production is concentrated primarily in one county, Weld, with 79% of cumulative production, although some production occurs in several other counties (95% of cumulative production has occurred within 4 counties). Significantly higher drilling rates, given higher prices, might temporarily reverse the current decline; nevertheless, the EIA’s outlook is highly unlikely to be realized given the maturity of the play and the fact that the EIA is counting on producing seven times the known unproved resources by 2040; hence the “extremely high” optimistic bias rating.

- The drop in rig counts in the Niobrara (15 in October 2016 vs. 64 in October 2014) has affected drilling rates and hence production. Should drilling rates increase significantly, given higher prices, the current production decline may reverse, at least temporarily. The AEO2016 projection that production can double and exit 2040 at all-time highs after producing an additional 2.9 billion barrels of oil is, however, highly unlikely to happen.

2.5 AUSTIN CHALK PLAY

Figure 15 illustrates the AEO2016 reference case forecast for the Austin Chalk play compared to AEO2014 and AEO2015. In AEO2016, the Austin Chalk is forecast to contribute 5% of all tight oil production from 2014 to 2040, and 10.6% of 2040 production. The Austin Chalk shares some counties in common with the Eagle Ford (Karnes is the top county in both plays) and extends from southern Texas to Louisiana, although most production is in Texas.

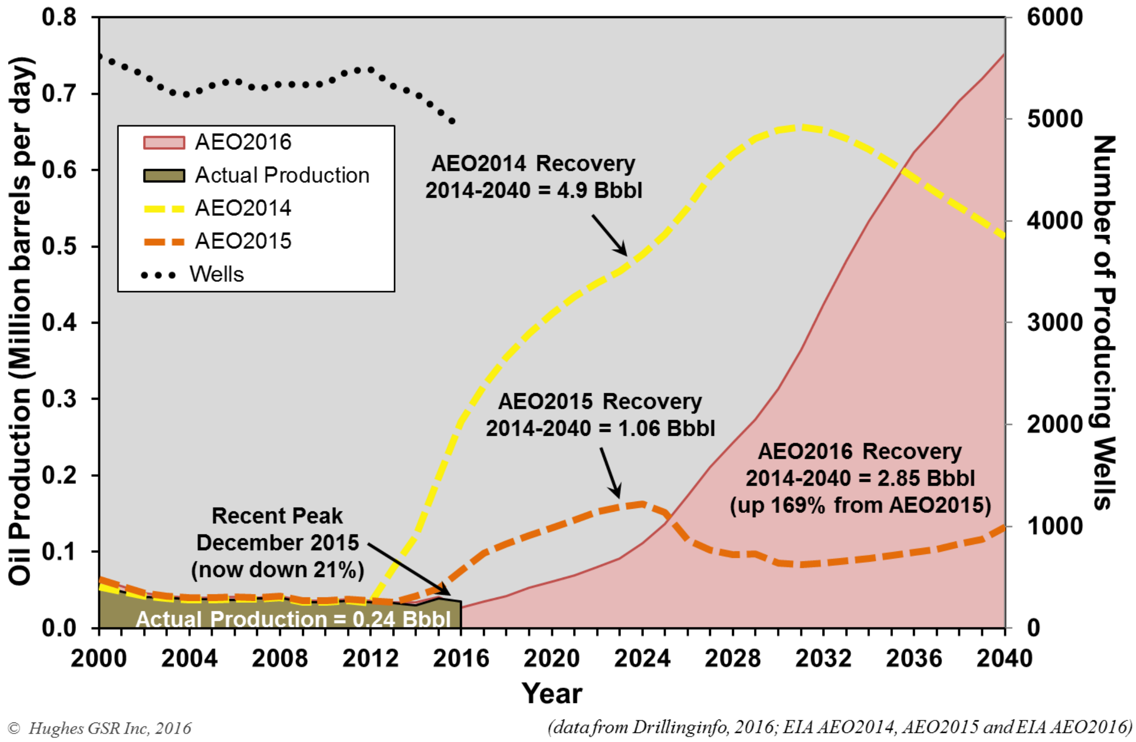

Figure 15. Austin Chalk Play production for AEO2016 compared to the EIA's AEO2014 and AEO2015 forecasts.

Also shown are the cumulative number of producing wells and cumulative production from 2000 to mid-2016 (.24 billion barrels).

The AEO2016 projection of 2.85 billion barrels over the 2014-2040 period is up 169% from AEO2015 and down 42% from AEO2014. The Austin Chalk is an old play being redeveloped with the latest technology, and more than 15,700 wells have been drilled there since the 1940s. The play has received increased drilling attention recently although the number of producing wells has gradually declined since 2000 to 4,913 (as of mid-2016) as older wells are taken out of production. The play reached an all-time peak in 1991 at .18 mbd and experienced a recent peak in December 2015 at .038 mbd and has declined 21% since then to .030 mbd.

If the AEO2016 forecast came to fruition, 52% of the EIA's estimate of "unproved technically recoverable resources" would be produced by 2040, with production exiting 2040 at .75 mbd, more than 20 times current levels. I rated the EIA's AEO2015 forecast as having a "high" optimism bias, as it had scaled back its wildly optimistic 2014 projection. With AEO2016 the EIA has returned to its former optimism for this play, hence this projection has to be rated as "very high", given that production is projected to increase 21-fold by 2040 and recover twice as much oil from 2014 to 2040 as has been recovered from this play since the 1940s.

Some observations:

- The Austin Chalk has produced 1.34 billion barrels since the 1940s and production is down 80% from its 1991 peak. The play, which has seen more than 15,000 wells drilled, is now benefiting somewhat from redevelopment with horizontal drilling and hydraulic fracturing, which increased production from 2010 to a recent peak in December 2015. *Drilling Deeper* did not develop a range of production projections for this play but did evaluate the fundamentals for assessment of the EIA projections.

- Although some future growth from the current low levels is a reasonable assumption if oil prices rise and drilling rates increase, AEO2016's projection that production can grow 21-fold from current levels by 2040 is extremely optimistic; hence the overall rating of a "very high" optimism bias.

- The drop in rig counts in Texas (906 in November 2014 vs. 214 in October 2016), will keep Austin Chalk production falling or flat, barring an increase in drilling rates.

2.6 "OTHER" PLAYS

Figure 16 illustrates the AEO2016 reference case forecast for "other" plays compared to AEO2015 and AEO2014. "Other" plays account for 16.3% of projected 2014-2040 tight oil production in AEO2016 and make up 23.2% of 2040 production. These plays include the Woodford and Monterey, estimated at 1.1% and 0.5% of 2014-2040 production, respectively, and other unnamed plays which make up the remaining 14.7%. "Other" plays are expected to grow rapidly to an all-time high in 2040, and total recovery over this period is up 22% compared to AEO2015.

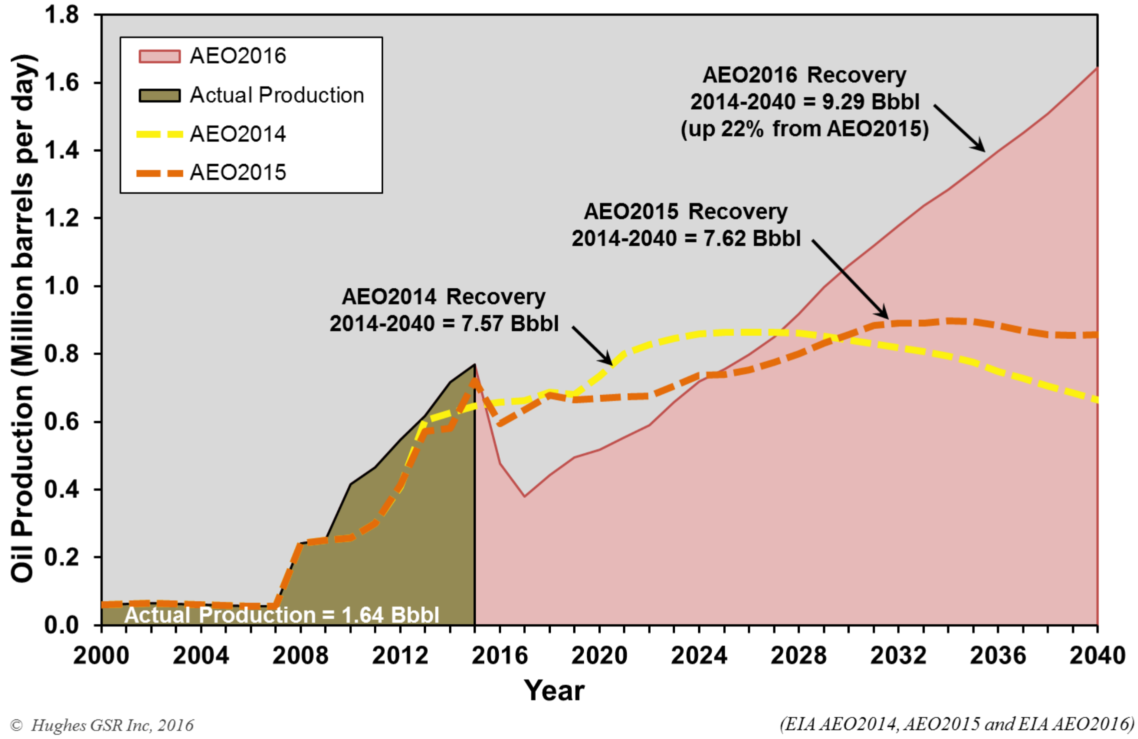

Figure 16. "Other" plays production in the EIA's AEO2016, AEO2015 and AEO2014 forecasts.

AEO2016 assumes an extremely aggressive production growth profile compared to the earlier projections. Also shown is cumulative production from 2000 to 2015 (1.64 billion barrels).

The AEO2016 production projection is extremely aggressive, turning around a recent production decline to grow more than 4-fold from 2017 levels to 1.64 mbd by 2040, when "other" plays would make up 23% of tight oil production. The optimism bias of "other" plays in AEO2016 is therefore rated as "high". Although there is certainly growth potential in plays like "SCOOP" in Oklahoma and other plays in the Permian Basin not included in the plays covered herein, even with an aggressive growth assumption "other" plays would make up less than half of the assumed output of the Bakken and Eagle Ford in 2040.

Exceptional tight oil plays are clearly not ubiquitous: the seven major plays reviewed in this report account for 84% of projected 2014-2040 tight oil production in AEO2016, and the Bakken and Eagle Ford alone account for 48%. All "other" established and emerging plays in the U.S., even allowing for the EIA's optimism, account for just 16%.

3 All Plays Comparison

Table 2 summarizes, by play, the production projections in AEO2016 and the optimism bias ratings I have assigned them. Some plays, like the Eagle Ford and Spraberry, have quite reasonable projections and are rated as having a "moderate" optimism bias. But these are countered by extremely optimistic projections for plays like the Bakken, Wolfcamp, and Niobrara, taking into consideration play fundamentals, total recovered resources compared to "unproved technically recoverable resources," and the exit level of production in 2040. Hence the overall optimism bias for AEO2016 is "very high."

Play	2014-2040 Production (billion barrels)	% of 2014-2040 Production	% of 2040 Production	EIA Optimism Bias (Hughes)
Bakken	18.65	32.8%	32.0%	Extremely High
Eagle Ford	8.67	15.2%	9.5%	Moderate
Wolfcamp	5.98	10.5%	10.3%	Extremely High
Spraberry	5.35	9.4%	6.2%	Moderate
Bone Spring	3.26	5.7%	3.0%	Very High
Niobrara	2.90	5.1%	5.0%	Extremely High
Austin Chalk	2.85	5.0%	10.6%	Very High
Other	9.29	16.3%	23.2%	High
Total	**56.95**	**100.0%**	**100.0%**	**Very High**

Table 2. Projected tight oil recovery, production in 2040, and optimism bias for AEO2016 plays assessed in this report.

Note that "other" includes the Woodford and Monterey plays as listed in Table 1.

Figure 17 illustrates the comparison of aggregate production for the Bakken and Eagle Ford from the *Drilling Deeper* "Most Likely" production forecasts, compared to forecasts from AEO2016, AEO2014 and AEO2015. (The comparison of all plays in AEO2016 to AEO2015 and AEO2014 is illustrated in Figure 6.) These two plays are "new", in the sense that they were made possible by the combination of horizontal drilling and hydraulic fracturing technology. By comparison, the other plays covered herein have produced oil for decades and are now benefiting from the application of horizontal drilling and hydrofracturing technology to increase recovery and tap previously inaccessible resources.

The net increase in cumulative production between AEO2016 and AEO2015 in these two plays is a result of the EIA's extremely optimistic revision of the Bakken. Whereas—compared to the "Most Likely" *Drilling Deeper* forecast—the AEO2014 projection overstated 2014-2040 production by 42%, and the AEO2015 projection by 92%, the AEO2016 projection is overstated by 115%. As noted in the discussion of the Bakken play there is no apparent basis for this increase, other than the assumption that vast undrilled areas of the Three Forks will become highly productive, which, if realized, would see the Bakken recover more than double the USGS mean estimate of "technically" recoverable resources by 2040. (As noted earlier, "technically" recoverable resources are not necessarily "economically" recoverable.)

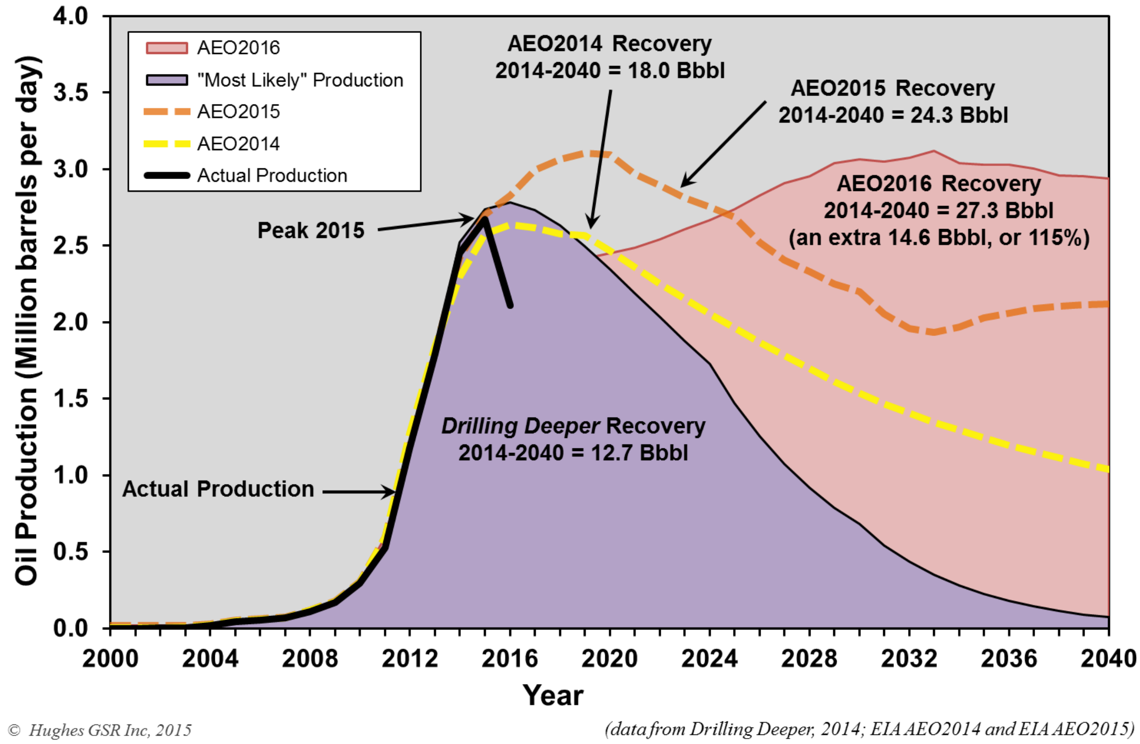

Figure 17. Comparison of the AEO2016 projection to AEO2014 and AEO2015 for the Bakken and Eagle Ford plays combined, compared to the "Most Likely" forecast for these plays in *Drilling Deeper*.

Actual production, which has amounted to 3.94 billion barrels through mid-2016, is also shown. *Drilling Deeper* projected the recovery of 12.7 billion barrels for 2014-2040 compared to the AEO2016 estimate of 27.3 billion barrels, some 115% higher. This is entirely the result of the extremely optimistic projection for the Bakken as the EIA's projection for the Eagle Ford is quite reasonable.

The AEO2016 projections represent a very good news story for those hoping for a lasting tight oil boom with relatively low oil prices. Total 2014-2040 tight oil recovery projections are up 19% from AEO2015 and 37% from AEO2014. A detailed look at these projections by play reveals that they have on average a "very high" optimism bias based on an analysis of current and historical production, the distribution of sweet spots, the level of drilling to date, and the projected high-degree of recovery of "unproved technically recoverable resources".

3.1 VOLATILITY OF EIA PLAY LEVEL FORECASTS

One measure of the potential reliability of future production estimates from the EIA is how much successive forecasts change over time. Certainly everyone is entitled to change their mind, but the geological fundamentals of the major tight oil plays are now relatively well known and don't change wildly from year to year. Although average well productivity has increased somewhat in some plays in the last two years it has declined in others (Figure 4), so large differences in technology cannot account for major differences between projections. Wild swings in projected production rates and cumulative recovery between forecasts, in the absence of significant new information to account for it, indicates a basic lack of robustness in the methodology used for estimation.

Despite the fact that the EIA projections by play examined herein were made only one year apart, they exhibit major differences in future production rates and in estimated oil recovery. Figure18 illustrates the magnitude of production rate differences between AEO2015 and AEO2016 by play in percentage terms. Plays have been revised both upward and downward by amounts exceeding 50 percent in some plays/years, but overall have been revised upward, and 2040 production has been revised upward in all plays.

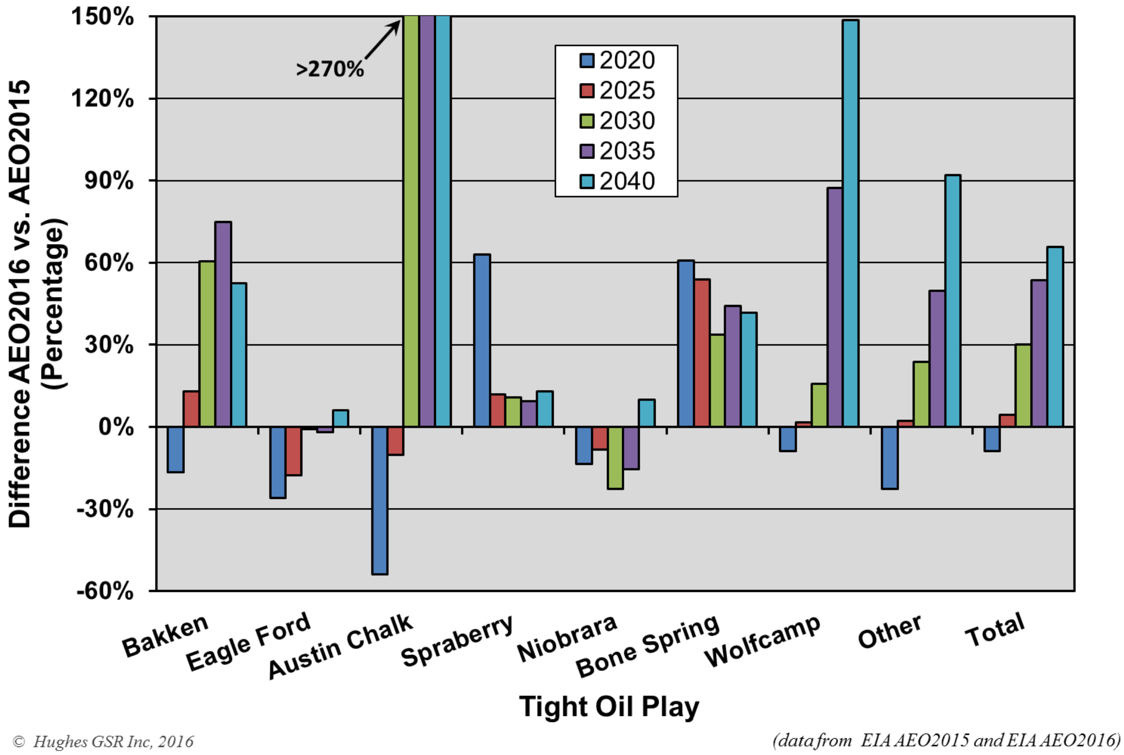

Figure 18. Comparison of projections by play from AEO2016 and AEO2015 by year.

Comparison is made in terms of the percentage difference in production rates in AEO2016 versus in AEO2015 for the years 2020, 2025, 2030, 2035 and 2040. Revisions in production rates are more than 50% in several years/plays, and production in 2040 has been increased in every play and by 66% overall.

Figure 19 illustrates the changes in total oil recovery from 2014 to 2040 between AEO2015 and AEO2016. Although two of the seven major plays have been revised downward somewhat, the upward revisions of the Bakken, Austin Chalk, Spraberry, Bone Spring, Wolfcamp, and "other" plays—which ranged between 21% and 65%—resulted in a total increase in projected production of 9.2 billion barrels, or 19% more in AEO2016 than AEO2015. Downward revisions occurred in the Eagle Ford and Niobrara of 11% and 10%, respectively.

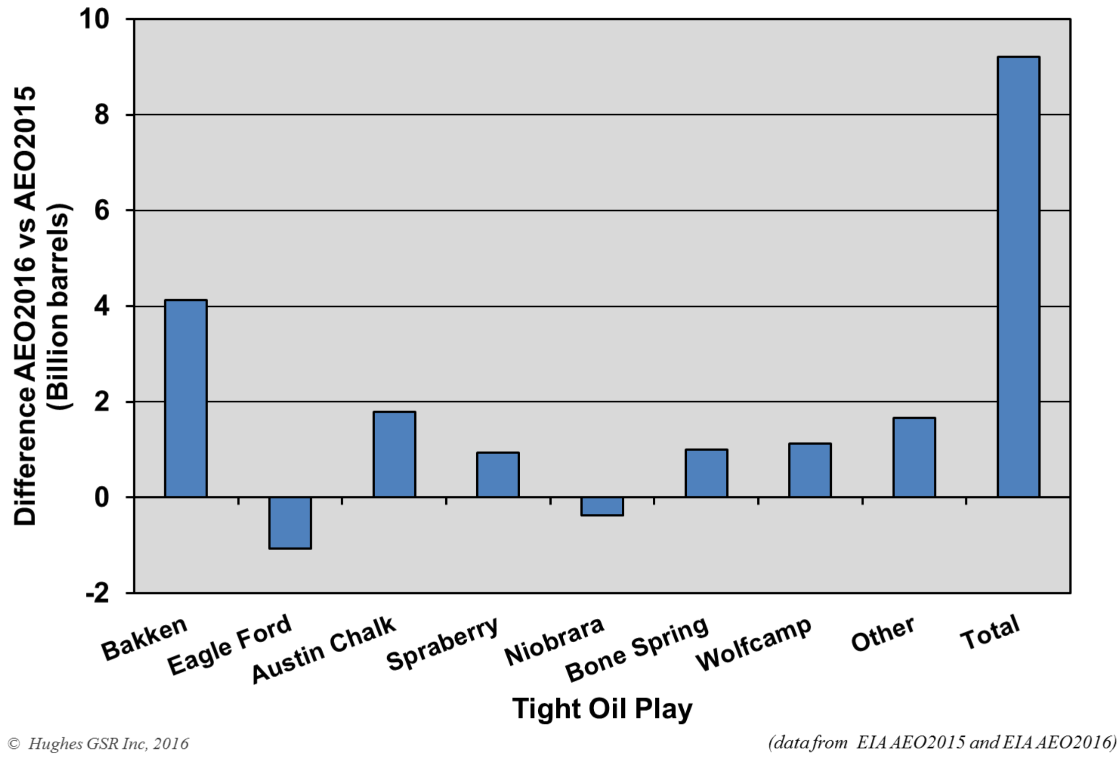

Figure 19. Comparison of projections by play from AEO2016 and AEO2015 in terms of total oil production from 2014 to 2040.

Overall production has increased by 9.2 billion barrels, or 19%, in AEO2016 compared to AEO2015.

The EIA offers no explanations for the volatility and optimism of its projections. Geological fundamentals appear to have little to do with it, given that major plays are now quite well understood. Assumptions of vastly improved technology in the future may be a factor, although improvement in average well quality has stagnated or is falling in some of the core area counties of major plays like the Bakken[18] and Eagle Ford[19] as sweet spots are drilled off. Another factor may be the assumption of much closer downspacing, resulting in far larger numbers of available drilling locations than previously thought, although well interference is already being observed in top counties of the Bakken and Eagle Ford, which discounts this.[20], In the case of the Bakken, vast undrilled areas have been assumed to be prospective from the Three Forks, and production has been added from this source by the EIA, but this remains highly speculative at best. The volatility between successive forecasts and the increase in overall production cannot be attributed to changes in future oil price assumptions either, given that prices for WTI are at or lower in AEO2016 than AEO2015 through 2030 and are $6.56/barrel lower in 2040.

The volatility, optimism, and lack of transparency in EIA tight oil production projections inspire little confidence in their reliability. This is a major concern for future energy policy decisions given the weight that many in government and industry place on them.

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[18] Hughes, Bakken Reality Check.

[19] J. David Hughes, *Eagle Ford Reality Check: The Nation's Top Tight Oil Play After More Than a Year of Low Oil Prices*, (Post Carbon Institute, December 2015), http://www.postcarbon.org/publications/eagle-ford-reality-check/.

[20] Hughes, *Bakken Reality Check*. Hughes, *Eagle Ford Reality Check*.

4 Summary and Implications

Since peaking in March 2015, U.S. tight oil production has declined by 19% as of November 2016—a reduction in the production rate of more than one million barrels per day—according to the EIA's monthly *Drilling Productivity Report*[21] (it had declined by 13% as of June 2016 per Drillinginfo, as shown in Table 3). Only the Permian Basin has not peaked. When *Drilling Deeper* was published two years ago all plays were in ascent, rig counts were at all-time highs and the price of oil was just beginning its collapse. Yet the analysis of play fundamentals then showed that production peaks were not far off.

A key point in Table 3 is also that prolific tight oil plays are not ubiquitous, as some would have us believe: the Permian plays (Wolfcamp, Spraberry, and Bone Spring), the Bakken, and the Eagle Ford together made up 79% of June 2016 production.

Play	Peak date	Peak production rate (kbd)	Production rate as of June 2016 (kbd)	% below peak as of June 2016	% of total production as of June 2016	EIA Optimism Bias (Hughes)
Bakken	Dec-14	1218.43	995.54	18.3%	23%	Extremely High
Eagle Ford	Mar-15	1605.72	1112.62	30.7%	26%	Moderate
Wolfcamp	-	-	327.09	-	8%	Extremely High
Spraberry	-	-	726.55	-	17%	Moderate
Bone Spring	May-15	266.38	231.49	13.1%	5%	Very High
Niobrara	Feb-15	190.96	122.55	35.8%	3%	Extremely High
Austin Chalk	Dec-15	38.52	30.47	20.9%	1%	Very High
Other	Mar-14	1103.06	703.89	36.2%	17%	High
Total	**Mar-15**	**4886.93**	**4250.21**	**13.0%**	**100.0%**	**Very High**

Table 3. Peak, decline, and EIA optimism bias of tight oil plays.[22]

Note that these data, from Drillinginfo, will differ somewhat from the more commonly referenced EIA *Drilling Productivity Report* (DPR) data, which is estimated for recent months.

[21] Energy Information Administration, *Drilling Productivity Report* (October 2016), http://www.eia.gov/petroleum/drilling/archive/2016/10/.

[22] Historical data are from Drillinginfo, a commercial database of well production data widely used by industry and government, including the EIA. See http://info.drillinginfo.com.

Future production of tight oil plays is a function of well quality, drilling rates, decline rates and the number of available drilling locations. These are dependent on geology and technology.

With regard to geology: Tight oil plays have a restricted areal extent, and all have higher productivity "core" areas or "sweet spots", which typically cover 15-20% of a play's area. The difference in well-productivity between sweet spots and other parts of a play can be 3:1 or more. *Drilling Deeper* assessed well productivity by county and used the EIA's 2014 estimate of well density to determine the total number of available locations in making production forecasts. High decline rates are a fact of life with tight oil plays, and new technology has not changed that.[23]

With regard to technology: the fossil fuel industry has responded to the challenge of low oil prices by focusing drilling on "sweet spots"— a practice known as "high grading"—and applying more aggressive technology. This has resulted in average well productivity going up in some plays (Figure 4). Most of this increase is due to high grading, with about a third due to better technology.[24] A review of well costs and trends for the Bakken reveals that, compared to 2006, well lateral length has doubled to 10,000 feet, fluid per well has increased 6-fold to 3.7 million gallons, and proppant used per well has increased 7-fold to 4 million pounds[25] (Chesapeake recently reported using 50 million pounds on a Haynesville well).[26] Similar trends are evident in other plays. This has certainly improved individual well production, but as each well can now drain more of the reservoir it has reduced the number of locations available to drill. The net effect is that, at a constant drilling rate, better technology will exhaust a play more quickly at a lower cost—but will not substantially increase ultimate recovery.

The improvement in the number of wells a rig can drill per unit of time has partially offset the effect on production of the steep decline in rig counts since mid-2014, and has improved economics. The service industry's rate cuts have also had a major impact on the economics of the average well.[27] But there are a limited number of drilling locations in sweet spots, and high grading plus the downturn in oil prices has resulted in their exhaustion at disproportionately high rates, leaving higher-cost oil for later. An analysis of top counties in plays like the Bakken and Eagle Ford shows that average well productivity has begun to decline, meaning that the best locations have been exhausted along with possible well interference (from wells being drilled too close together).[28]

My "very high" optimism bias rating for the overall EIA AEO2016 tight oil forecast is based on the fundamentals, given what is known from an analysis of well quality and production data from subareas within each play. A final note on this optimism is Figure 20, which shows that the EIA assumes that production will begin to grow strongly in 2017, despite a 37% decline in drilling rate from peak levels in 2014. Tight oil and shale gas production are forecast to grow 88% from 2014 levels to all-time highs by 2040, while drilling rates remain below 2014 levels to 2040 (see Figure 20), with only a modest increase in oil price (see Figure 3).

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[23] Mark Passwaters, "Geology over technology: Bernstein warns of limits to shale production bonanza," *SNL Interactive*, October 11, 2016, https://www.snl.com/Interactivex/article.aspx?CdId=A-37986003-11566.

[24] Abraham, "Analyst touts industry's cost reductions in U.S. shale plays."

[25] EIA and IHS, *Trends in U.S. Oil and Natural Gas Upstream Costs*, March 2016, https://www.eia.gov/analysis/studies/drilling/.

[26] Joe Carroll and David Wethe, "Chesapeake Energy Declares 'Propageddon' With Record Frack," *Bloomberg*, October 20 2016, http://www.bloomberg.com/news/articles/2016-10-20/chesapeake-declares-propageddon-with-record-frack-in-louisiana.

[27] Abraham, "Analyst touts industry's cost reductions in U.S. shale plays."

[28] Hughes, *Bakken Reality Check*. Hughes, *Eagle Ford Reality Check*.

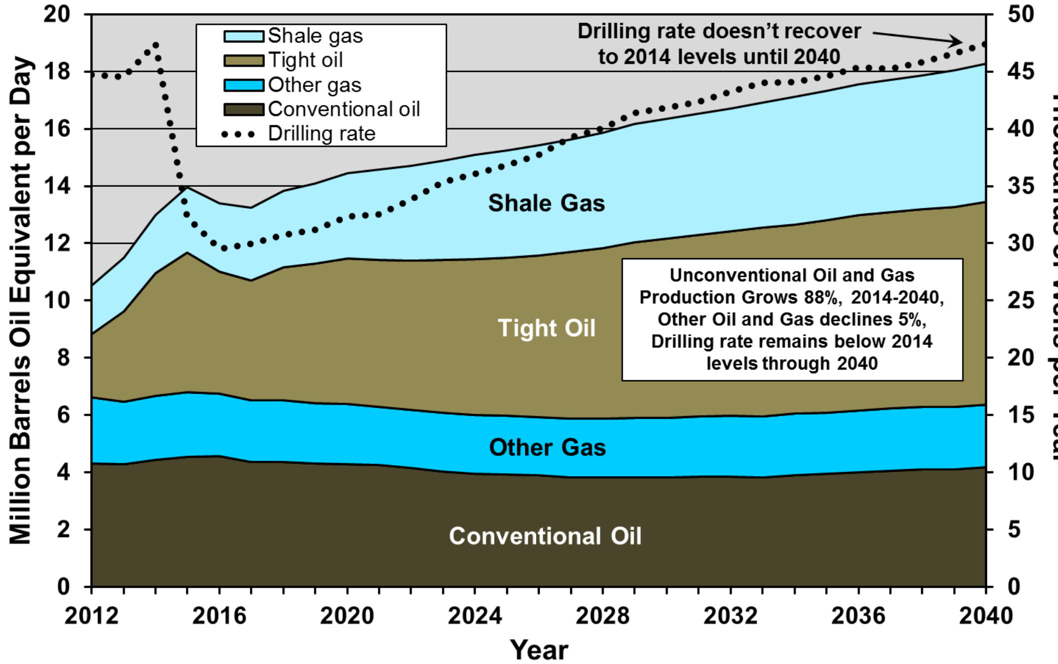

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Figure 20. Growth in oil and gas production versus estimated drilling rates for the AEO2016 reference case projection.

The EIA drilling rates shown in Figure 20 require a little over one million wells to be drilled between 2015 and 2040. At an average cost of $6 million each, this represents an investment of $6 trillion.

The EIA uses a program known as the National Energy Modelling System (NEMS) for forecasting. The program is complex: a statement at the EIA's NEMS link says, "Most people who have requested NEMS in the past have found out that it was too difficult or rigid to use."[29]

The play-level analysis in this report raises some important questions: If NEMS is truly a robust system for forecasting, why is there so much difference at the play level between AEO2015 and AEO2016 when play fundamentals have changed little? Why does Bakken production rise 128% from current levels, recover more than twice as much oil by 2040 as the latest USGS mean estimate of technically recoverable resources, and exit 2040 at production levels more than double current levels? How can a decades-old play like the Austin Chalk increase production 21-fold over current levels, compared to the modest forecast in AEO2015, and recover twice as much oil by 2040 as it has recovered since the 1940s? How can overall tight oil production increase by 19% in AEO2016 compared to AEO2015 while assuming oil prices are the same or lower over the 2015-2040 period?

The EIA's projections for oil production are very important, as they are widely used by industry and government policy makers as a definitive estimate of what is likely to happen. The crude oil export ban has been lifted after 40 years on the assumption that tight oil production will be robust for the foreseeable future at relatively low prices. Getting it wrong has very serious implications for energy policy and future energy security, considering that the EIA is the country's premier source for future production projections. This analysis shows that the EIA has erred on the side of extreme optimism in its tight oil production forecasts, which are highly unlikely to be realized.

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[29] Energy Information Administration, *Availability of the National Energy Modeling System (NEMS) Archive*, May 2016, https://www.eia.gov/forecasts/aeo/pdf/info_nems_archive.pdf.