2016 SHALE GAS 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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About the Author

David Hughes is an earth scientist who has studied the energy resources of Canada for four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager. He developed the National Coal Inventory to determine the availability and environmental constraints associated with Canada's coal resources. As team leader for Unconventional Gas on the Canadian Gas Potential Committee, he coordinated a comprehensive assessment of Canada's unconventional natural gas potential.

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.

Hughes is president of Global Sustainability Research, a consultancy dedicated to research on energy and sustainability issues. He is also a board member of Physicians, Scientists & Engineers for Healthy Energy (PSE Healthy Energy) and is a Fellow of Post Carbon Institute. Hughes contributed to *Carbon Shift*, an anthology edited by Thomas Homer-Dixon, and his work has been featured in *Nature*, *Canadian Business*, *Bloomberg, USA Today*, as well as other popular press, radio, and television outlets.

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.

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By J. David Hughes. In association with Post Carbon Institute.
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For reprint requests and other inquiries, contact: Post Carbon Institute, 613 Fourth St., Suite 208, Santa Rosa, CA, 95404
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U.S. gas production was thought to be in permanent decline as recently as 2005. The advent of shale gas over the past decade has, however, dramatically turned this around and increased production to all-time highs. Notwithstanding this, U.S. gas production peaked in mid-2015 and shale gas production peaked in early 2016, according to the Energy Information Administration (EIA).[1,2] The question is: How fast and how much can production grow in the future given higher prices and a return to higher rates of drilling? Given that shale gas is the major source of hope for growing or even maintaining U.S. gas production, a view to the future of shale gas production is critical for establishing energy policy and avoiding unforeseen supply shortfalls.

EIA forecasts of gas production published in its Annual Energy Outlook (AEO) are viewed by industry and government policy makers 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 report *Drilling Deeper*, published in October 2014, I reviewed the credibility of the EIA's *Annual Energy Outlook 2014* (AEO2014)[3] 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 each of the major shale gas plays.[4] The EIA's AEO2014 reference case projection over-estimated gas recovery from 2014 to 2040 by 53% compared to the "Most Likely" *Drilling Deeper* case. AEO2015[5] and AEO2016[6] were 50% and 83% higher, respectively, than *Drilling Deeper* for the same period. The EIA projections are likewise considerably more optimistic than those of the University of Texas Bureau of Economic Geology (UTBEG) for the four plays it has assessed.[7]

The EIA recently released AEO2016 and kindly provided the underlying play-by-play production estimates for shale gas 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 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 32).

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1 Energy Information Administration, "Natural Gas Monthly," September 2016, http://www.eia.gov/naturalgas/monthly/.

2 Energy Information Administration, "Natural Gas Weekly," October 2016, http://www.eia.gov/naturalgas/weekly/.

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

4 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/.

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

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

7 J. Browning, et al., "Study forecasts gradual Haynesville production recovery before final decline," *Oil and Gas Journal*, December 2015; http://www.ogj.com/articles/print/volume-113/issue-12/drilling-production/study-forecasts-gradual-haynesville-production-recovery-before-final-decline.html.

1.1 KEY FUNDAMENTALS

Key fundamentals used in projecting future production of shale gas plays *in Drilling Deeper* were:

- **Rate of well production decline:** Shale gas plays have high well production decline rates, typically in the range of 75-85% in the first three years.
- **Rate of field production decline:** Shale gas 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 shale gas 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 gas 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 generally low gas prices in the past several years has led gas producers to focus 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.

1.2 OVERALL FORECAST COMPARISON TO PAST YEARS

How have the EIA's projections changed in 2016? Figure 1 compares cumulative production through 2040 in the AEO2016 projections to the "Most Likely" drilling rate forecasts in *Drilling Deeper* and to projections in AEO2014 and AEO2015, as well as to cumulative production to date. All plays have peaked in the past few years; the key questions are whether these peaks can be reversed with higher prices and drilling rates, and what the cumulative production over the forecast period is likely to be.

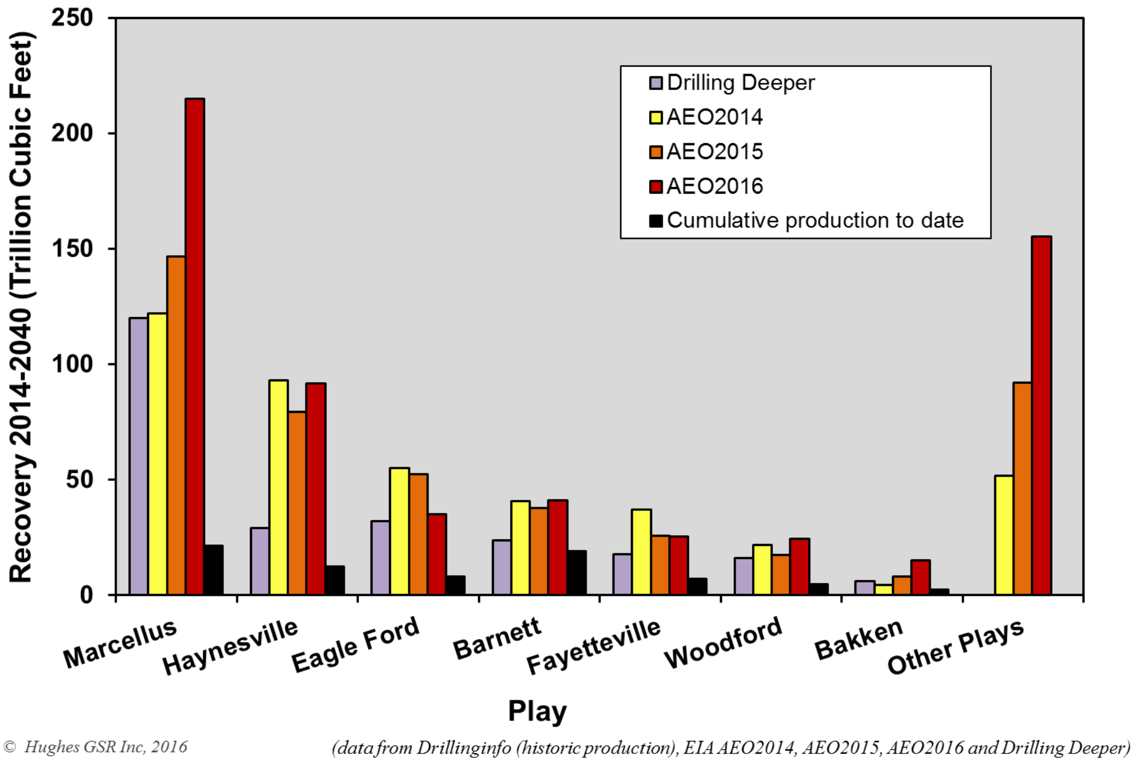


Figure 1. Cumulative recovery by play from 2014 to 2040 comparing AEO2014, AEO2015, AEO2016, and *Drilling Deeper* "Most Likely" projections.

The most significant increases occur in the Marcellus and "other" plays, although all plays are revised upward in AEO2016 compared to AEO2015 except the Eagle Ford and Fayetteville. All plays are below peak production. Also shown is cumulative production to date, per Drillinginfo.[8]

Some general observations with respect to the assumptions and projections in AEO2016:

- EIA assumes natural gas prices will remain at or below $5/MMbtu through 2040, when they will be $4.85/MMbtu ($2015). This is 20% below its AEO2015 price forecast over the 2015-2040 period. Gas prices at the time of writing were about $3.00/MMbtu and were over $12.00/MMbtu as recently as 2008.

- EIA assumes production from shale gas will grow much faster than projected in AEO2015, with 2014-2040 production increasing by 144 trillion cubic feet (Tcf), or 31%, over its 2015 projection.

[8] Historical production data used in this report's figures and tables are from 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.

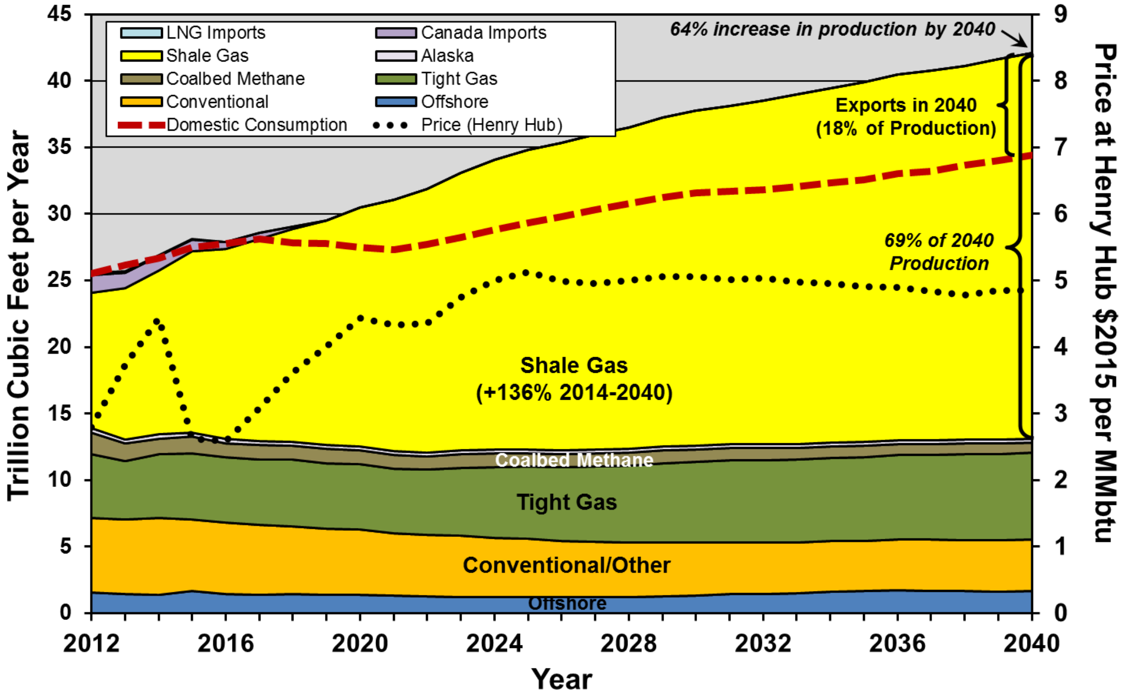
- The seven major plays analyzed in *Drilling Deeper*, which constituted 89% of AEO2014 projected shale gas production through 2040, amount to just 74% of 2014-2040 production in the AEO2016 projection. Production is projected to grow aggressively in the Utica and other unnamed plays.

- Thirty-six percent of production through 2040 is projected to come from the Marcellus and 65% from just three plays—the Marcellus, Haynesville and Utica—highlighting yet again that high quality shale gas plays are not ubiquitous.

- Considering that AEO2015 and AEO2016 are just 12 months apart, there is a lot of change in projected production profiles for individual plays and total production—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. natural gas production by source, with price projections. All eggs are in the shale gas basket, with production forecast to grow by 136% over 2014 levels by 2040, when it will constitute 69% of production. Conventional, coalbed methane, and offshore gas are expected to decline and tight gas to increase slightly, such that non-shale sources of gas are essentially flat through 2040. Overall U.S. gas production is forecast to grow by 64%, with 18% of production available for export in 2040. Prices are forecast to remain low, at or below $5/MMbtu through 2040, which is 20% lower than in AEO2015 on average over the 2015-2040 period.



© Hughes GSR Inc, 2016 *(data from EIA Annual Energy Outlook 2016, Tables 13 and 14, http://www.eia.gov/forecasts/aeo/er/excel/yearbyyear.xlsx)*

Figure 2. AEO2016 reference case forecast of gas production by source from 2012-2040.

Also shown is projected price (Henry Hub in 2015 dollars per MMbtu) and projected domestic consumption.

This is an extremely bullish forecast compared even to AEO2015, especially considering the lower forecast prices. Gas production overall is projected to be 12% higher over the 2014-2040 period than in AEO2015—even without the Alaska gas pipeline which was part of the AEO2015 outlook—and shale gas production is projected to be 31% higher. Too good to be true? Very probably, given that the most economic parts of shale gas plays are being drilled now (core areas or sweet spots) leaving the highest-cost parts of these plays for later—which will require higher prices and higher drilling rates to maintain let alone grow production. There has been much industry rhetoric about lower break-even prices for shale gas 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 than many thought; however, production is falling in all seven major shale gas 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 shale gas production from the seven major plays assessed in AEO2016 as well as "Other" plays (note that the Antrim and Utica, which were assessed separately in AEO2016, are considered part of "Other", or "Rest of US", plays for the purposes of this report). All plays are below peak production, and although the Marcellus and Utica are down less than 5%, the second largest play, the Haynesville, is down 53% since peaking in January 2012. Five legacy plays—which made up more than half of shale gas production when they collectively peaked in August 2012—were down 32% as of August 2016. The combined peak of all plays occurred in February 2016 at 5% above August 2016 levels.

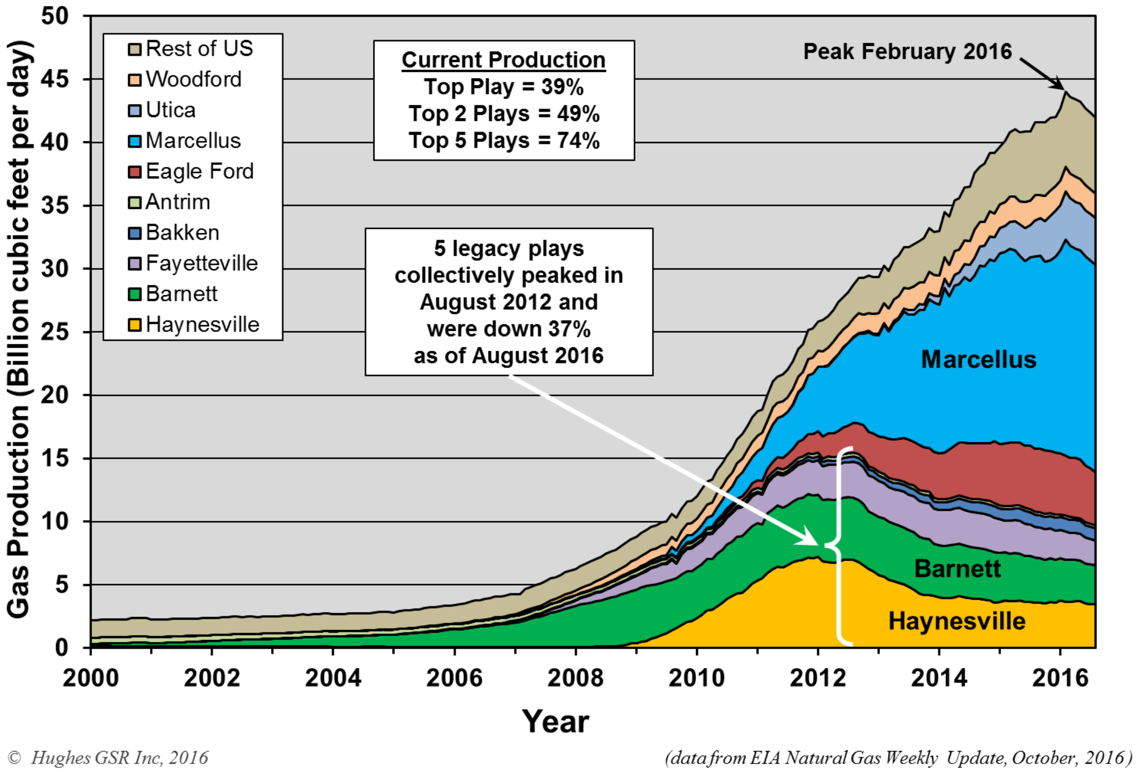


Figure 3. Shale gas production by play from 2010 through June 2016.

All plays are below peak production and the collective peak occurred in February 2016 at 5% above August 2016 production levels.

With the drop in oil and gas 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 Woodford exhibit some improvement in the last year and the Haynesville exhibits significant improvement (the Haynesville has recently been the focus of some of the largest frack jobs ever attempted[10]). This is due to a combination of drilling sweet spots (given that core areas are now well established in most plays) and better technology (drilling sweet spots is thought to be nearly twice as

[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] 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.

important as better technology in reducing well costs, according to IHS Markit[11]). Even with the significant improvement in well productivity, Haynesville production is down 53% from its January 2012 peak.

The focus on better technology, however, will not necessarily increase overall recovery. 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, 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 quality portions of shale plays and maintain production. Typically, sweet spots comprise less than 20% of total play area.

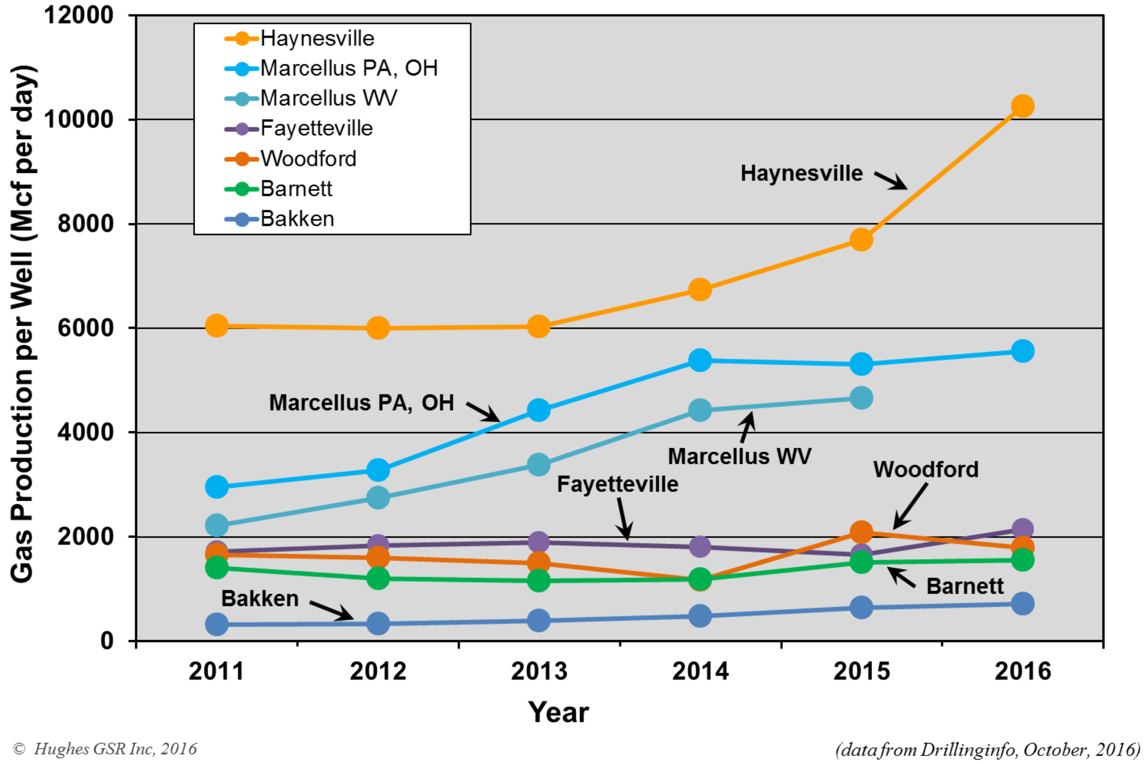


Figure 4. Average first-six-months well production by year for major shale gas plays, 2011-2016.

All plays have increased slightly in the last year except for the Woodford, with the Haynesville up significantly. These increases are due to better technology and the focus on drilling sweet spots. (**Note that Marcellus well productivity data for 2016 were not available for West Virginia at the time of writing.**)

Given the relatively high field decline rates for shale gas 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. The Barnett, where shale gas production got started in the 1990s, is a mature play with more than 20,000 wells drilled, and now exhibits a negative number of producing well additions as more than 4,000 wells have ceased to produce and wells are being shut down faster than they are being drilled (the Barnett is down 38% from its peak production in 2011). The other major plays have also all exhibited a substantial decrease in producing well additions since oil and gas prices began to decline in mid-2014. The number of producing wells added to the major plays peaked in December 2014 at an annual rate of

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

9,122. *Drilling Deeper*, which was published in October 2014 based on mid-2014 data, did not anticipate the severity of the price decline and the resultant radical downturn in drilling rates, and hence was too optimistic in its "Most Likely" scenario of future production for some plays as discussed in the following section.

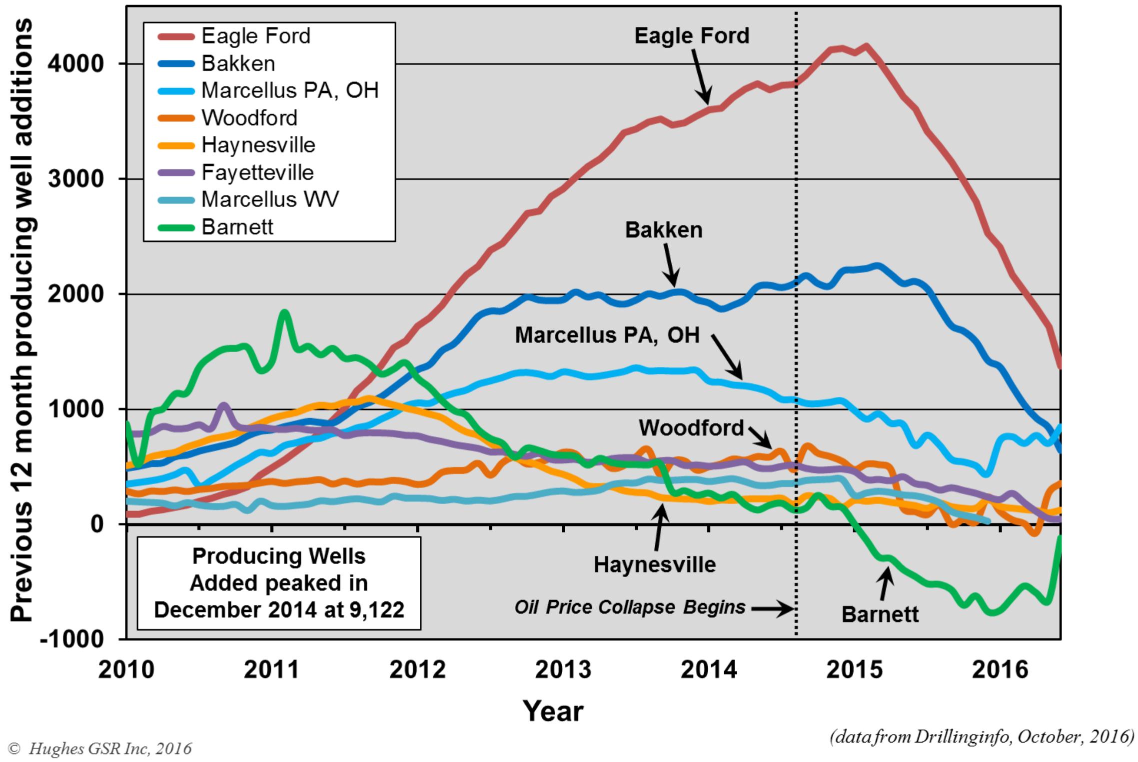


Figure 5. Annual net addition of new producing wells for major shale gas plays, 2010 through June 2016.

This is the sum of new producing wells added and wells that ceased production in the previous 12 months. The Barnett, which is the most mature shale gas play, has more wells being retired than are coming on production in recent years.

The question is: How much, and how quickly, can shale gas production ramp up with price increases? The EIA is extremely 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 ever higher prices to support the increasing number of lower productivity wells needed to maintain production, let alone grow it. The following look at the shale gas forecasts by individual play gives a better perspective on the credibility of the EIA projections.

2 Shale Gas Production by Play

Figure 6 illustrates the AEO2016 reference case forecast by shale gas play compared to AEO2014 and AEO2015. Half of projected production comes from just two plays, the Marcellus and Haynesville, and the Marcellus alone accounts for 36% of projected production for 2014-2040. Cumulative production in AEO2015 was 459 Tcf, or 9% higher than AEO2014, Cumulative production in AEO2016 is 603 Tcf, which is 144 Tcf, or 31%, higher than AEO2015, and 43% higher than AEO2014. Shale gas is projected to ramp up much more steeply than in the earlier forecasts, and exit 2040 on an upward trajectory at production levels of more than double current rates—implying that vast additional amounts of shale gas will be produced from these plays post-2040.

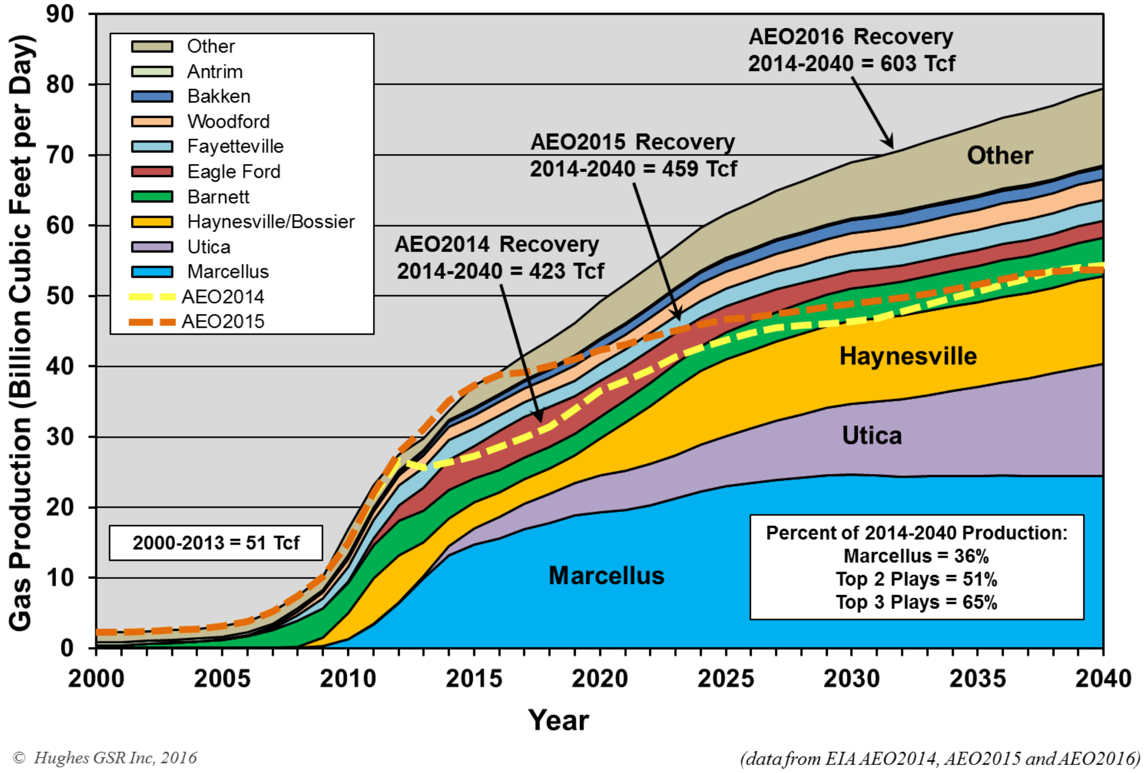


Figure 6. AEO2016 reference case forecast of gas production by shale gas play for 2012-2040, compared to AEO2014 and AEO2015.

The EIA is even more bullish than last year assuming 2014-2040 production will be 31%, or 144 Tcf, higher than AEO2015. Sixty-five percent of 2014-2040 production is projected to come from just three plays.

This is an extremely bullish forecast. Sixty-five percent of 2014-2040 shale gas production is forecast to come from just three plays, and half from the Appalachian region (Marcellus and Utica). In total, according to this forecast, 65% of the "unproved technically recoverable shale gas resources" (as of January 1 2013[12]) will be consumed by 2040; 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 65% and 245% of the unproved resources for the seven major plays reviewed in this report are forecast to be produced by 2040 (the Utica, Antrim and "Other" are not reviewed in detail), and

[12] 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.

for the top two plays, the Marcellus and Haynesville, recovery is projected to be 147% and 128%, respectively, of unproved resources. For the major plays reviewed herein, which AEO2016 projects will provide 75% of 2013-2040 production, the EIA projection counts on recovering 154% of the "unproved technically recoverable resources" that existed on January 1, 2013. Assuming recovery 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 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 (Tcf)	Gas recovery 2013-2040 (Tcf)	% recovered by 2040
Marcellus	148.7	218.42	146.9%
Haynesville	73.3	93.55	127.6%
Eagle Ford	55.4	36.25	65.4%
Barnett	17.5	42.81	244.6%
Fayetteville	20.4	26.55	130.2%
Woodford	20.5	24.90	121.5%
Bakken	12.1	15.32	126.6%
Utica	54.6	84.30	154.4%
Antrim	12.7	2.57	20.3%
Other	534.1	69.14	12.9%
Total	**949.3**	**613.81**	**64.7%**

Table 1. Unproved technically recoverable shale gas resources as of January 1, 2013, compared to forecast production by play from 2013 to 2040 in the EIA AEO2016 reference case.[13]

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.

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

2.1 MARCELLUS PLAY

Figure 7 illustrates the AEO2016 reference case forecast for the Marcellus compared to AEO2014, AEO2015 and the "Most Likely" drilling rate case from *Drilling Deeper*. In AEO2016, the Marcellus is forecast to contribute 36% of all shale gas production from 2014 to 2040, and 31% of 2040 production. The play peaked in February 2016 and was down 5% as of August 2016.[14]

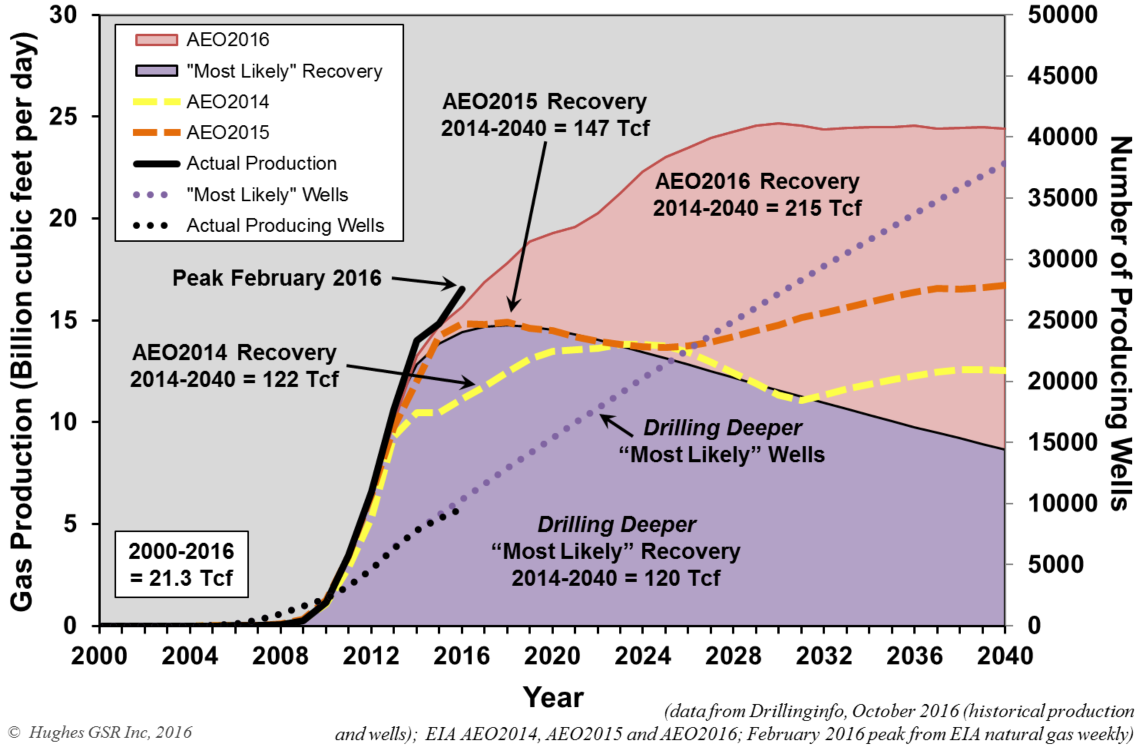


Figure 7. Marcellus Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

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 21.3 Tcf. AEO2016 estimates cumulative recovery over the 2014-2040 period of 215 Tcf, compared to 120 Tcf in *Drilling Deeper*. The February 2016 production peak is not reflected as data in this figure are in 1-year intervals.

The EIA has increased 2014-2040 recovery from the Marcellus in AEO2016 to 215 Tcf, which is 47% (or 68 Tcf) higher than AEO2015, and 76% (or 93 Tcf) higher than AEO2014. This is nearly triple the 2011 USGS mean estimate[15] of 84 Tcf of undiscovered technically recoverable resources for the Marcellus and 47% higher than the EIA's own 2015 estimate of "unproved technically recoverable resources".[16] By contrast, the "Most Likely" forecast for 2014-2040 recovery in *Drilling Deeper*, at 120 Tcf, is comparable to the EIA's AEO2014 estimate.

[14] Energy Information Administration, "Natural Gas Weekly."

[15] J. L. Coleman, et al., *Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province*, U.S. Geological Survey, 2011; https://pubs.usgs.gov/fs/2011/3092/pdf/fs2011-3092.pdf.

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

The Marcellus is the largest U.S. shale gas play and is mainly concentrated in Pennsylvania, but also includes eastern Ohio, northern West Virginia and southern New York state. The core counties delineated by cumulative production are illustrated in Figure 8. The top two counties, located in northeast Pennsylvania, have accounted for 37% of cumulative gas production, and the top five counties, all within Pennsylvania, have accounted for 65%. The top counties are surrounded by many others with generally much lower well productivity.

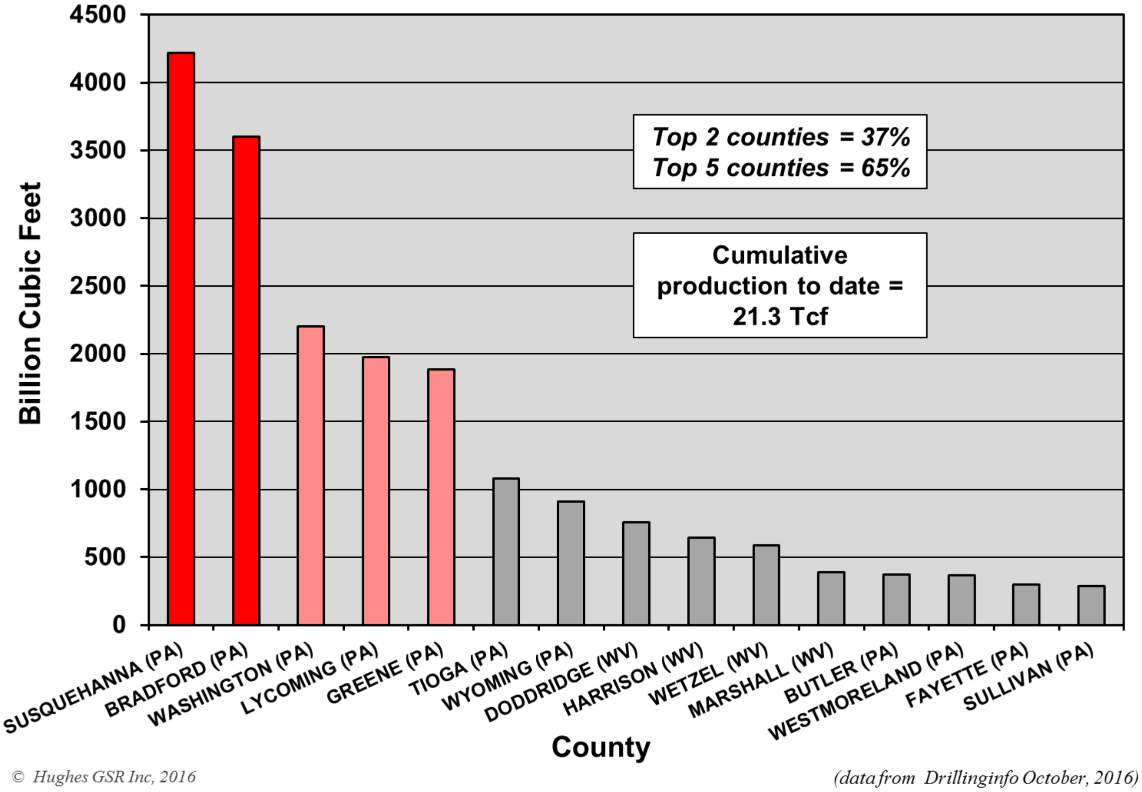


Figure 8. Marcellus Play cumulative gas production by county through mid-2016.

The optimism bias of the EIA's AEO2016 Marcellus reference case projection is rated as "extremely high", given that it calls for producing 47% more gas than the EIA's own estimate of "unproved technically recoverable resources" (and nearly triple the USGS estimate), that it would require much higher drilling rates than anything experienced so far, and the fact that the projection exits 2040 at near record production levels implying that vast additional, as yet unknown, resources will be produced post-2040. Given pushback on the environmental implications of fracking, limitations in the number of available drilling locations, and the fact that top counties are already showing evidence of well saturation, it is extremely unlikely that this projection will come to fruition.

Some observations:

- More than 9,600 wells are now producing in the Marcellus with more than 50,000 drilling locations remaining for full development. Much of the recent drilling has focused on top counties, however, preferentially consuming the highest quality locations. This means that higher prices will be required to support drilling in the much larger portion of the play with poorer quality rock, with correspondingly higher drilling rates to maintain—let alone grow—production.

- The current downturn in drilling rates will prolong the plateau of Marcellus production and conserve drilling locations for later. Significantly higher drilling rates may increase production, at least temporarily, but the drilling that would be required to grow production to the level projected by the EIA and sustain it would consume available drilling locations well before 2040, setting the stage for a production collapse.

- The drop in rig counts in the Marcellus (34 in October 2016 vs. 143 in January 2012) has cut the rate of producing well additions by 38% from peak rates in mid-2013 and has curtailed production growth (Figure 5). Greater rig efficiencies, continuing installation of take-away pipeline infrastructure to connect new wells, better technology, and the inventory of drilled but not completed wells (DUCs) has limited the impact on production and producing well additions from what it otherwise might have been. Nonetheless the EIA's AEO2016 forecast is extremely unlikely to be realized.

2.2 HAYNESVILLE PLAY

Figure 9 illustrates the AEO2016 reference case forecast for the Haynesville compared to AEO2014, AEO2015 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2016, the Haynesville is forecast to contribute 15% of all shale gas from 2014 to 2040, and 16% of 2040 production. The play peaked in January 2012 and was down 52% as of August 2016.[17]

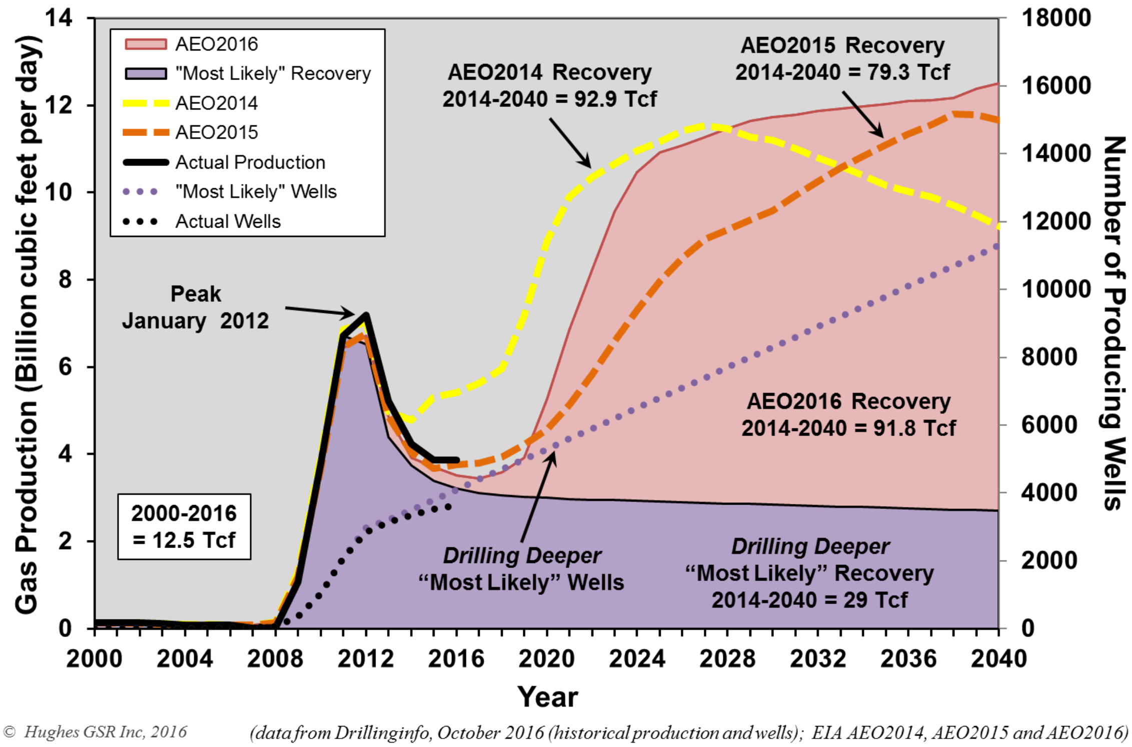


Figure 9. Haynesville Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

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 12.5 Tcf. AEO2016 estimates cumulative recovery over the 2014-2040 period of 92 Tcf, compared to 29 Tcf in *Drilling Deeper*.

The EIA has increased 2014-2040 recovery from the Haynesville in AEO2016 to 92 Tcf, which is 16% (or 13 Tcf) higher than AEO2015, and 1% (or 1 Tcf) lower than AEO2014. This is more than triple the University of Texas Bureau of Economic Geology base case estimate[18] of 46 Tcf of cumulative production by 2064 from wells drilled through 2045 (equivalent to 27.3 Tcf between 2014-2040 considering 8.7 Tcf was produced for 2006-2013 and likely at least 10 Tcf would be produced in its model for 2040-2064). The EIA AEO2016 estimate is also more than triple the "Most Likely" estimate of 29 Tcf for 2014-2040 production in *Drilling Deeper*, which is slightly higher than the University of Texas estimate.

The Haynesville is the second largest U.S. shale gas play in terms of projected 2014-2040 recovery and is prospective in Louisiana and eastern Texas. The core counties delineated by cumulative production to

[17] Energy Information Administration, "Natural Gas Weekly."

[18] J. Browning, et al., "Study forecasts gradual Haynesville production recovery before final decline," *Oil and Gas Journal*, December 2015; http://www.ogj.com/articles/print/volume-113/issue-12/drilling-production/study-forecasts-gradual-haynesville-production-recovery-before-final-decline.html.

date are illustrated in Figure 10. The top two counties, located in Louisiana, have produced 55% of cumulative production, and the top five counties, which include Panola County in Texas, have produced 77%. The top counties are surrounded by several others with generally much lower well productivity.

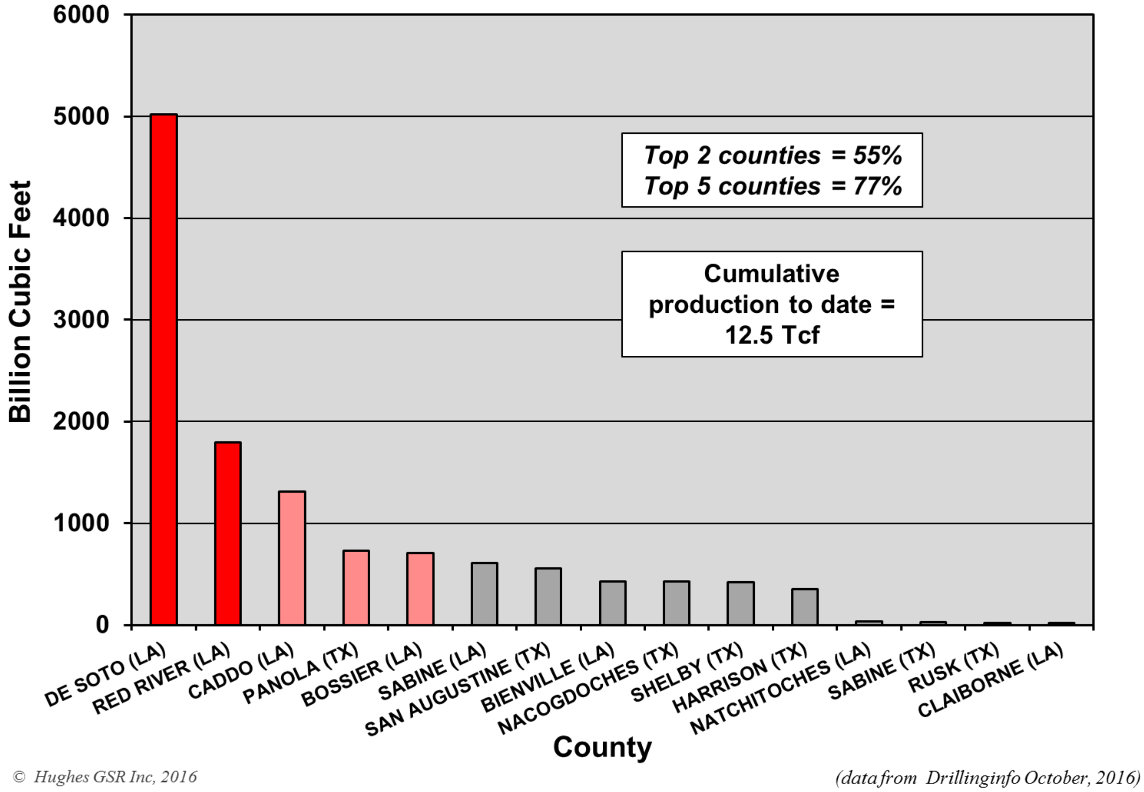


Figure 10. Haynesville Play cumulative gas production by county through mid-2016.

The optimism bias of the EIA's AEO2016 Haynesville reference case projection is rated as "extremely high", given that it calls for producing 28% more gas by 2040 than the EIA's own estimate of "unproved technically recoverable resources" and triple the estimates of the University of Texas and *Drilling Deeper*. Furthermore, the EIA projects that production will exit 2040 at all-time highs, implying that vast additional, presently unknown resources will be produced post-2040. The drilling rates required to do this, in the unlikely event that the resources exist—even considering the well quality improvements due to some of the largest frack jobs attempted anywhere so far[19]—would exhaust available drilling locations well before 2040 and would require higher prices than forecast by the EIA. Thus it is extremely unlikely that this projection will be realized.

Some observations:

- More than 3,600 wells are now producing in the Haynesville with approximately 17,000 drilling locations remaining for full development. Much of the recent drilling has focused on top counties, preferentially consuming the highest quality locations. This means that higher prices will be required to support drilling in the much larger portion of the play with poorer quality rock, with correspondingly higher drilling rates to maintain, let alone grow, production.

[19] Joe Carroll and David Wethe, "Chesapeake Energy Declares 'Propageddon' With Record Frack."

- Producing well additions peaked at nearly 1100 per year in mid-2011 (Figure 5) just before Haynesville production peaked. In order to nearly double peak production, as forecast by the EIA, drilling rates would have to grow to 2000 per year or more, which would consume available drilling locations before 2030, setting the stage for a production collapse of 30% per year or more. There are, however, ample drilling locations remaining to sustain the Haynesville on its current production plateau and gentle decline through 2040 as projected in *Drilling Deeper*.

- The drop in rig counts in the Haynesville (17 in October 2016 vs. 161 in February 2011) has cut the rate of producing well additions by 90% from peak rates in mid-2011 (Figure 5) and has resulted in a 52% drop in production from peak. Greater rig efficiencies, better technology, and the inventory of drilled but not completed wells (DUCs) has limited the impact on production and producing well additions somewhat from what it otherwise might have been. Nonetheless the EIA's AEO2016 forecast is extremely unlikely to be realized.

2.3 EAGLE FORD PLAY

Figure 11 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, Eagle Ford is forecast to contribute 5.8% of all shale gas from 2014 to 2040, and 3% of 2040 production. The play peaked in September 2015 and was down 17% as of August 2016.[20]

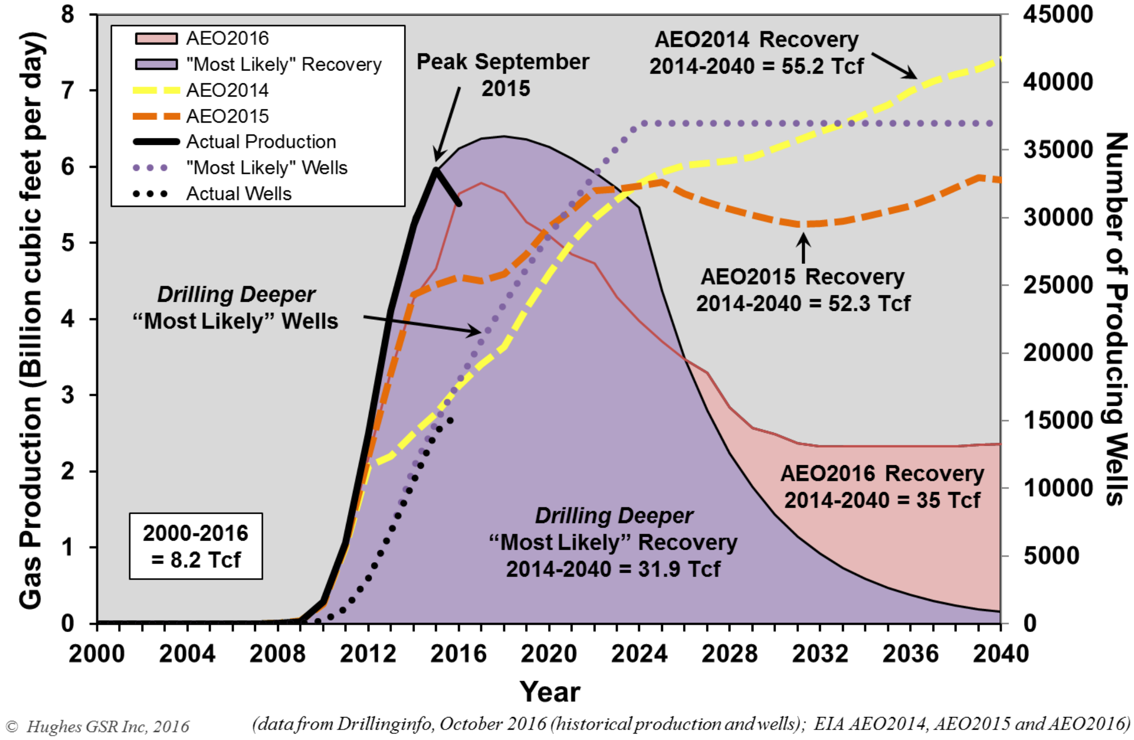


Figure 11. Eagle Ford Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

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 8.2 Tcf. AEO2016 estimates cumulative recovery over the 2014-2040 period of 35 Tcf, compared to 31.9 Tcf in *Drilling Deeper*.

The AEO2016 projection has decreased 2014-2040 recovery from the Eagle Ford to 35 Tcf, which is 33% (or 17 Tcf) lower than AEO2015, and 36% (or 20 Tcf) lower than AEO2014. This is 10% higher than the "Most Likely" estimate of 31.9 Tcf for 2014-2040 production in *Drilling Deeper*, and would consume 65% of the EIA's estimate of "unproved technically recoverable resources" (Table 1).

The Eagle Ford is the fifth largest U.S. shale gas play in terms of projected 2014-2040 recovery and the gas-prone portion is located in southern Texas downdip (to the southeast), of counties that are the main producers of oil. The core counties delineated by cumulative production to date are illustrated in Figure 12. The top two counties have produced 44% of cumulative production, and the top five counties have produced 83%. The top counties are surrounded by several others with generally much lower well productivity for gas but some have high oil productivity.

[20] Energy Information Administration, "Natural Gas Weekly."

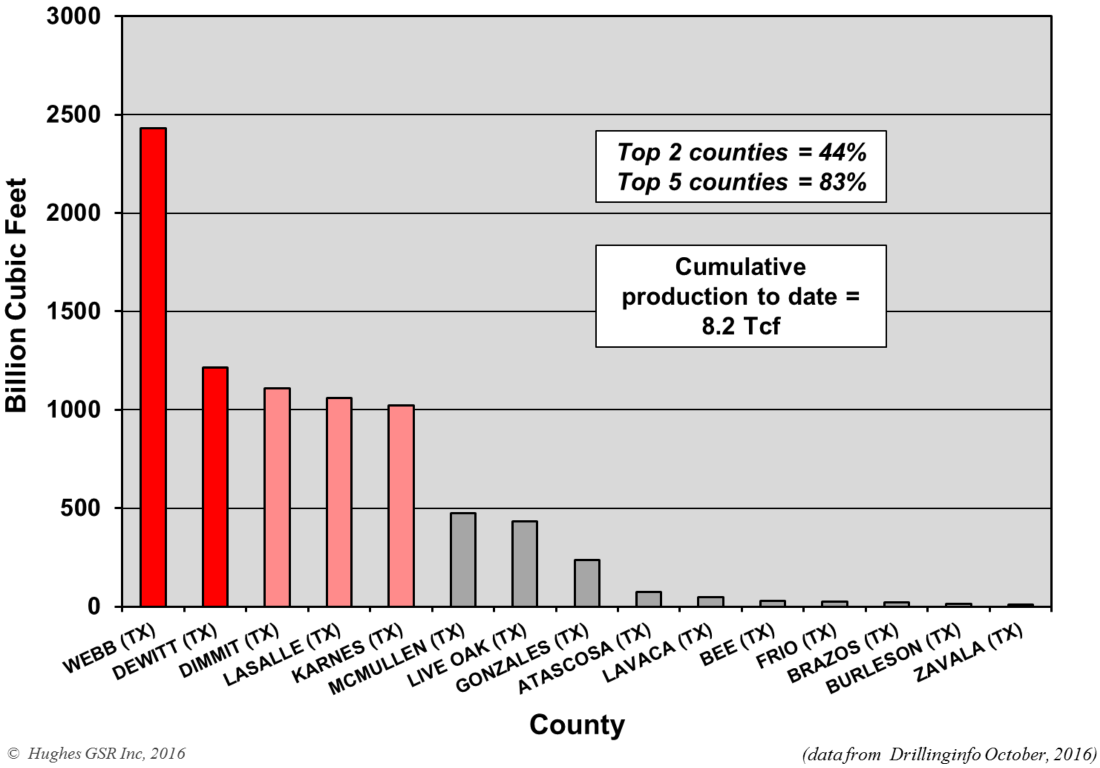


Figure 12. Eagle Ford Play cumulative gas production by county through mid-2016.

The optimism bias for the EIA's AEO2016 Eagle Ford reference case projection is rated as "moderate", given that its projection is plausible in terms of the needed drilling rate and the number of remaining drilling locations, and the fact that it doesn't require producing more gas than exists according to the EIA estimates of "unproved technically recoverable resources" (unlike the Marcellus, Haynesville and certain other plays).

Some observations:

- More than 15,500 wells are now producing in the Eagle Ford with approximately 21,000 drilling locations remaining for full development. Many of these wells were primarily drilled for oil production with secondary associated gas. Oil has therefore supported much of the gas production to date but drilling in gas prone areas alone will require higher prices especially as the highest quality portions are drilled off.

- Producing well additions peaked at over 4000 per year in mid-2014 (Figure 5) just before Eagle Ford oil production peaked. Producing well additions dropped to 1376 in mid-2016. The EIA production projections are quite reasonable given that available drilling locations will last longer than projected in *Drilling Deeper*, which assumed considerably higher drilling rates. The net effect, however, in terms of recovered gas by 2040 between the EIA and Drilling Deeper projections is that both are similar.

- The drop in rig counts in the Eagle Ford (33 in October 2016 vs. 259 in May 2012) has cut the rate of producing well additions by 60% from peak rates in mid-2011 (Figure 5) and has resulted in the 17% drop in gas production from peak. The fact that a lot of gas is produced by oil-directed drilling rigs, greater rig efficiencies, better technology, and the inventory of drilled but not completed wells (DUCs) has limited the impact on production from what it otherwise might have been.

2.4 BARNETT PLAY

The Barnett Play is where modern fracking got started in earnest in the 1990s and is the most mature shale play in the U.S. Figure 13 illustrates the AEO2016 reference case forecast for the Barnett compared to AEO2014, AEO2015, and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2016, the Barnett is forecast to contribute 6.8% of all shale gas from 2014 to 2040, and 6.9% of 2040 production. The play peaked in November 2011 and was down 38% as of August 2016.[21]

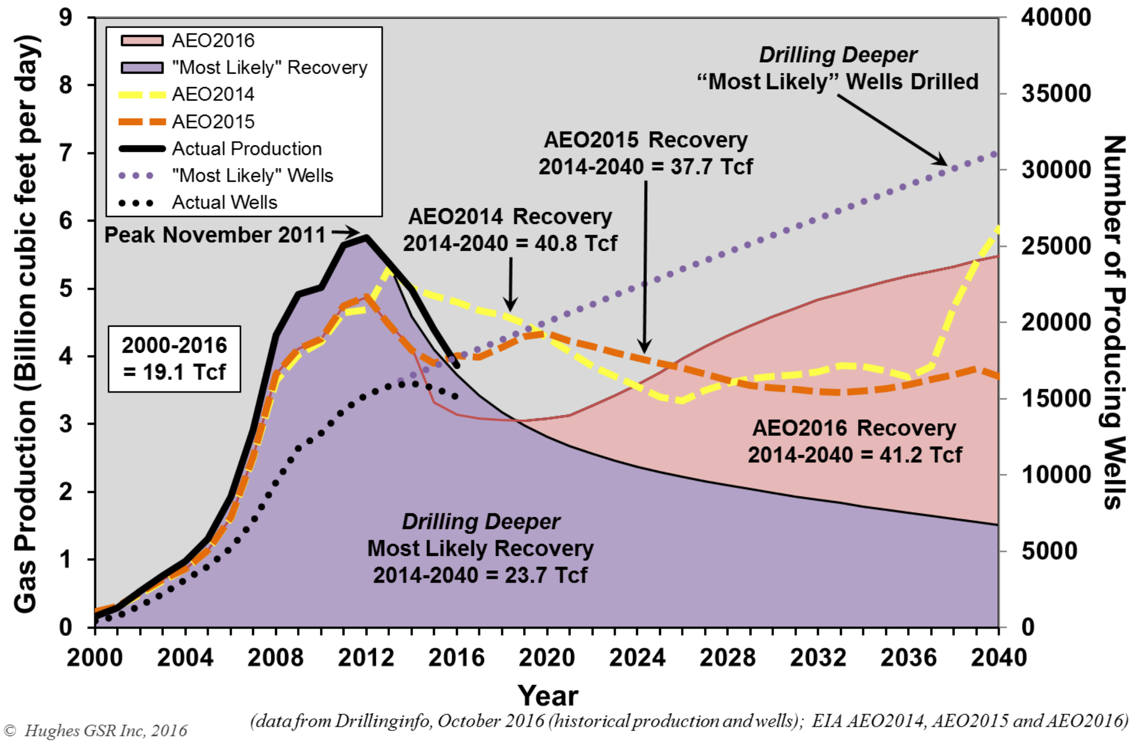


Figure 13. Barnett Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

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 19.1 Tcf. AEO2016 estimates cumulative recovery over the 2014-2040 period of 41 Tcf, compared to 24 Tcf in *Drilling Deeper*.

The EIA has increased 2014-2040 recovery from the Barnett in AEO2016 to 41.2 Tcf, which is 9% (or 3.5 Tcf) higher than AEO2015, and 8% (or 3 Tcf) higher than AEO2014. This is 62% higher the University of Texas Bureau of Economic Geology base case estimate[22] of 36.6 Tcf of cumulative production from 2011 to 2050 (equivalent to 25.5 Tcf for 2014-2040 considering 6.1 Tcf was produced for 2011-2013 and likely at least 5 Tcf would be produced in its model for 2040-2050). The EIA AEO2016 estimate is also much higher than the "Most Likely" estimate of 23.7 Tcf for 2014-2040 production in *Drilling Deeper*, which is similar to the University of Texas estimate (7% lower).

The Barnett is the fourth largest U.S. shale gas play in terms of projected 2014-2040 recovery and is located in eastern Texas. The core counties delineated by cumulative production to date are illustrated in

[21] Energy Information Administration, "Natural Gas Weekly."

[22] J. Browning, et al., *Barnett Shale Production Outlook*, (Society of Petroleum Engineers, July 2013); https://www.onepetro.org/journal-paper/SPE-165585-PA.

Figure 14. The top two counties have produced 56% of cumulative production, and the top five counties have produced 91%. The top counties are surrounded by several others with generally much lower well productivity.

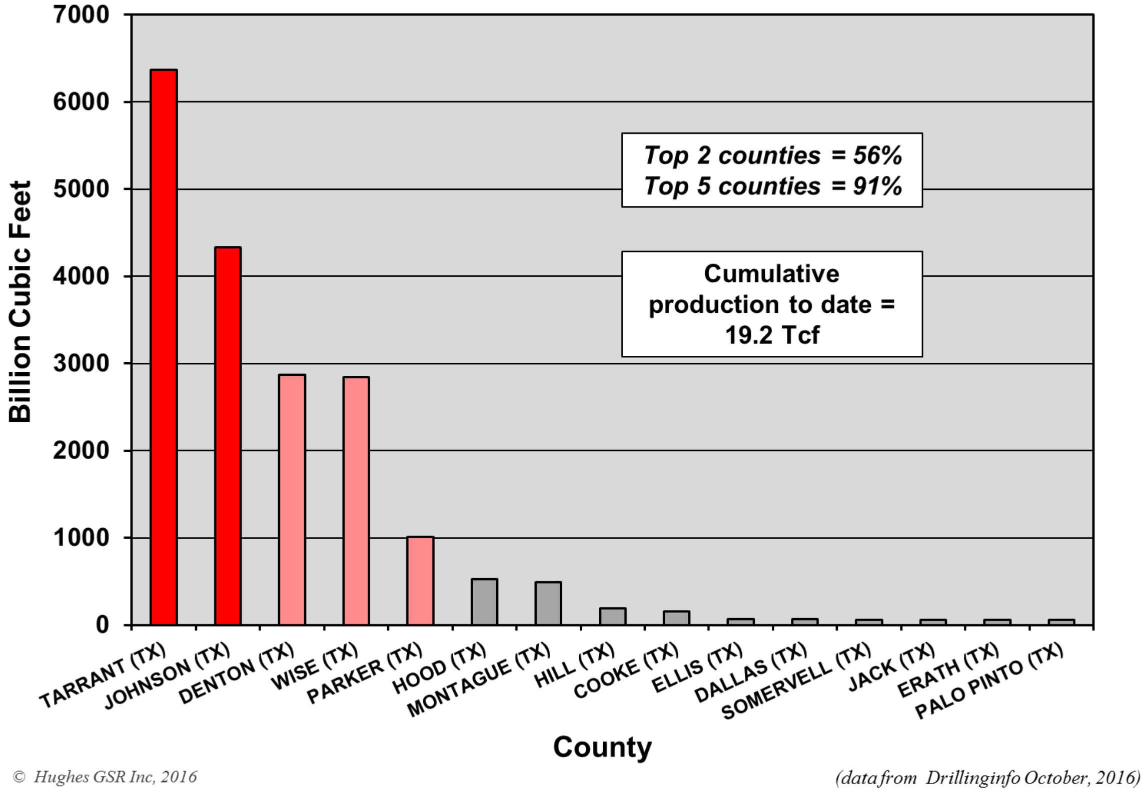


Figure 14. Barnett Play cumulative gas production by county through mid-2016.

The optimism bias of the EIA's AEO2016 Barnett reference case projection is rated as "extremely high", given that it calls for producing 145% more gas by 2040 than the EIA's own estimate of "unproved technically recoverable resources" and greater than 60% more than the estimates of the University of Texas and *Drilling Deeper*. Furthermore, the EIA projects that production will exit 2040 at near all-time highs, implying that vast additional, presently unknown, resources will be produced post-2040. The drilling rates required to do this, in the unlikely event that the resources exist, would exhaust available drilling locations well before 2040 and would require higher prices than forecast by the EIA. Thus it is extremely unlikely that this projection will be realized.

Some observations:

- More than 15,000 wells are now producing in the Barnett, which is down from more than 16,000 at peak as older wells cease to produce faster than new wells are being drilled. Of the more than 20,000 wells that have been drilled 5,000 are now shut-in. There are approximately 17,000 drilling locations remaining for full development. Much of the drilling has focused on the top counties which are now close to saturated with wells. This means that higher prices will be required to support drilling in the remainder of the play with poorer quality rock, and will require correspondingly higher drilling rates to maintain, let alone grow, production.

- Producing well additions peaked at 1548 per year in mid-2011 (Figure 5) just before Barnett production peaked. In order to increase production to near peak levels, as forecast by the EIA, drilling rates would have to grow to at least 1500 per year, given the depletion of high quality locations, which would consume available drilling locations before 2030, setting the stage for a production collapse.

- The drop in rig counts in the Barnett (3 in October 2016 vs. 60 in February 2011) is indicative of the industry's lack of enthusiasm for the Barnett at current prices, and has resulted in a negative growth rate for producing well additions as older wells are retired at a higher rate than new wells are added (Figure 5). Even considering greater rig efficiencies, better technology and the inventory of drilled but not completed wells (DUCs), it is hard to imagine a scenario, given the EIA's forecast low prices, where production could return to peak rates. Hence the EIA's AEO2016 forecast for the Barnett is extremely unlikely to be realized.

2.5 FAYETTEVILLE PLAY

Figure 15 illustrates the AEO2016 reference case forecast for the Fayetteville compared to AEO2014, AEO2015 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2016, the Fayetteville is forecast to contribute 4.2% of all shale gas from 2014 to 2040, and 3.7% of 2040 production. The play peaked in November 2012 and was down 33% as of August 2016.[23]

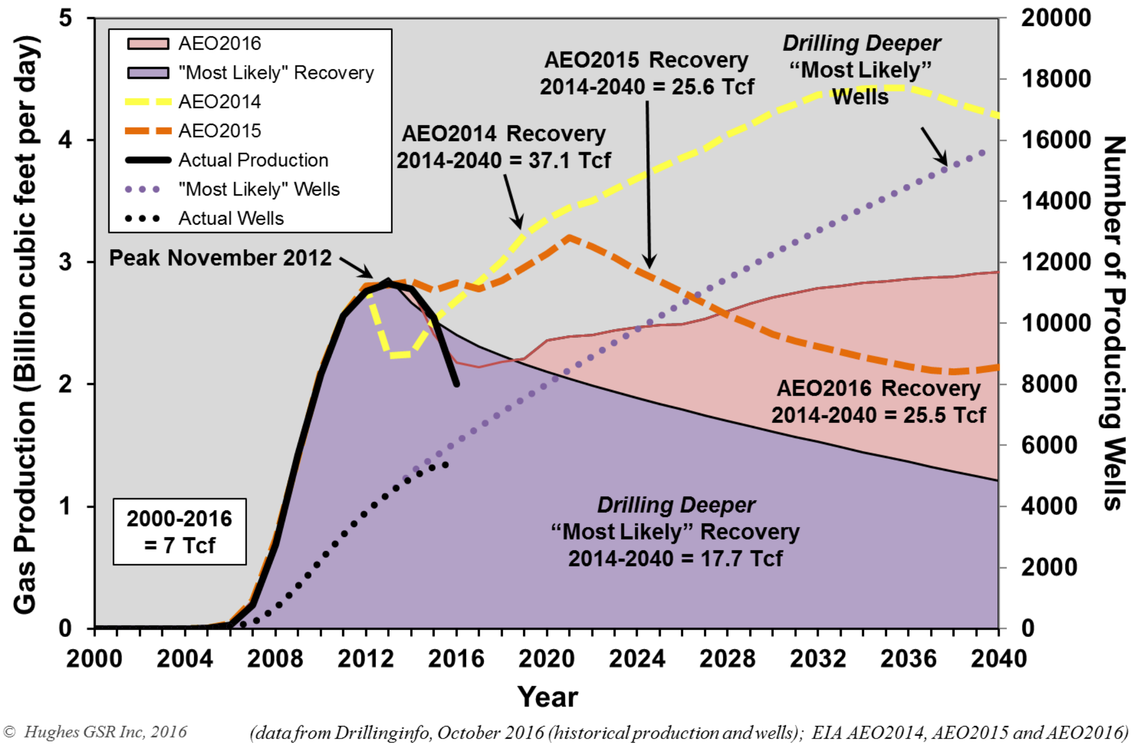


Figure 15. Fayetteville Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

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 7 Tcf. AEO2016 estimates cumulative recovery over the 2014-2040 period of 25.5 Tcf, compared to 17.7 Tcf in *Drilling Deeper*.

In AEO2016, the EIA has lowered 2014-2040 recovery from the Fayetteville slightly from AEO2015 to 25.5 Tcf, and by 31% (or 12 Tcf) below AEO2014. However, this is still more than double the University of Texas Bureau of Economic Geology base case estimate[24] of 18 Tcf of cumulative production by 2050 (equivalent to 10.5 Tcf for 2014-2040 considering 4.6 Tcf was produced from 2000 to 2013 and likely at least 2.9 Tcf would be produced in its model from 2040 to 2050). The EIA AEO2016 estimate is also 44% higher than the "Most Likely" estimate of 17.7 Tcf for 2014-2040 production in *Drilling Deeper* and 30% higher than its own estimate of "unproved technically recoverable resources" (Table 1).

[23] Energy Information Administration, "Natural Gas Weekly."

[24] J. Browning, et al., "Study develops Fayetteville shale reserves, production forecast," *Oil and Gas Journal*, January 2014, http://www.ogj.com/articles/print/volume-112/issue-1/drilling-production/study-develops-fayetteville-shale-reserves.html.

The Fayetteville is the sixth largest U.S. shale gas play in terms of projected 2014-2040 recovery and is located in Arkansas. The core counties delineated by cumulative production to date are illustrated in Figure 10. The top two counties have produced 53% of cumulative production, and the top five counties have produced 99%. There is little significant production beyond the top five counties.

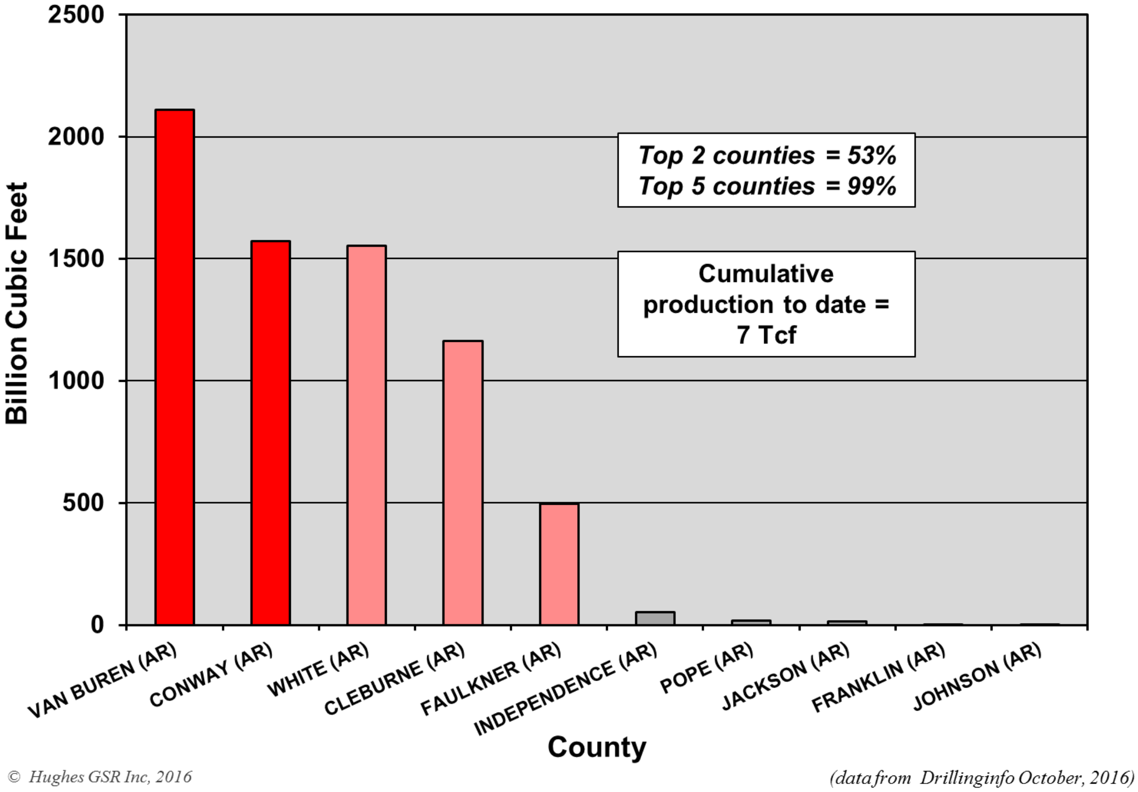


Figure 16. Fayetteville Play cumulative gas production by county through mid-2016.

The optimism bias of the EIA's AEO2016 Fayetteville reference case projection is rated as "high", given that it calls for producing 30% more gas by 2040 than the EIA's own estimate of "unproved technically recoverable resources", more than double the estimates of the University of Texas, and significantly more than the *Drilling Deeper* estimate. Furthermore, the EIA projects that production will exit 2040 at near all-time highs, implying that there are vast, as yet unknown, resources that will be produced post-2040. The drilling rates required to do this, in the unlikely event that the resources exist, would exhaust available drilling locations before 2035 and would require considerably higher prices than forecast by the EIA. Thus it is highly unlikely that this projection will be realized.

Some observations:

- More than 5,300 wells are now producing in the Fayetteville with approximately 11,000 drilling locations remaining for full development. Much of the recent drilling has focused on sweet spots, preferentially consuming the highest quality locations. This means that higher prices will be required to support drilling in the larger portion of the play with poorer quality rock, with correspondingly higher drilling rates needed to maintain, let alone grow, production.
- Producing well additions peaked at over 1000 per year in 2010 (Figure 5). In order to increase production to near the previous peak, as forecast by the EIA, drilling rates would have to grow to 1000 per year or more, which would consume available drilling locations before 2035, setting the stage for a production collapse. There are, however, ample drilling locations remaining to sustain the Fayetteville on its current gradual decline through 2040 as projected in *Drilling Deeper*.
- The drop in rig counts in the Fayetteville (1 in October 2016 vs. 34 in October 2011) has cut the rate of producing well additions by 95% from peak rates in 2010 (Figure 5) and has resulted in the 33% drop in production from peak. Greater rig efficiencies, better technology, and the inventory of drilled but not completed wells (DUCs) has limited the impact on production and producing well additions somewhat from what it otherwise might have been. Nonetheless the EIA's AEO2016 forecast that the Fayetteville can grow production to near peak levels by 2040 is highly unlikely.

2.6 Woodford Play

Figure 17 illustrates the AEO2016 reference case forecast for the Woodford compared to AEO2014, AEO2015 and the "Most Likely" drilling rate from *Drilling Deeper*. In AEO2016, the Woodford is forecast to contribute 4% of all shale gas from 2014 to 2040, and 3.7% of 2040 production. The play peaked in August 2014 and was down 13% as of August 2016.[25]

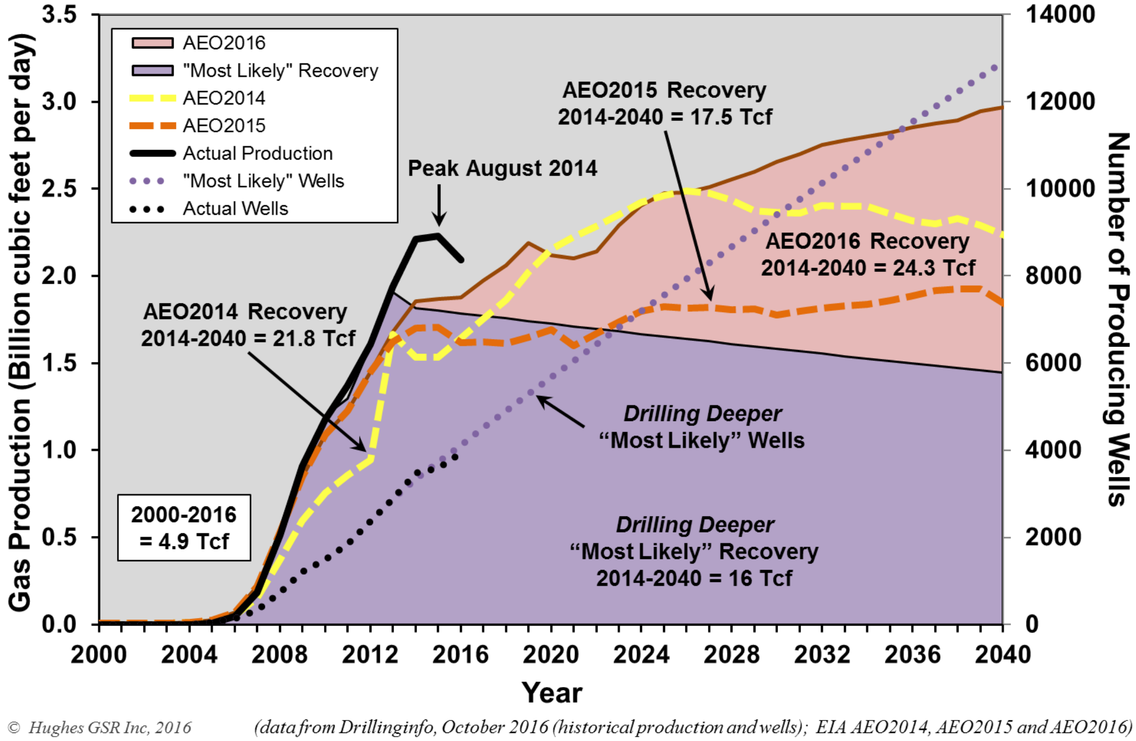


Figure 17. Woodford Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

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 4.9 Tcf. AEO2016 estimates cumulative recovery over the 2014-2040 period of 24.3 Tcf, compared to 16 Tcf in *Drilling Deeper*. (Note actual production shown is raw gas; the EIA applies a shrinkage factor of approximately 15%.)

The EIA has increased 2014-2040 recovery from the Woodford in AEO2016 to 24.3 Tcf, which is 39% (or 6.8 Tcf) higher than AEO2015, and 11% or (2.5 Tcf) higher than AEO2014. The EIA AEO2016 estimate of 2014-2040 production is also 22% higher than its own estimate of "unproved technically recoverable resources" (Table 1) and 52%, or 8.3 Tcf, higher than the "Most Likely" estimate of *Drilling Deeper*.

The Woodford is the seventh largest U.S. shale gas play in terms of projected 2014-2040 recovery and is located in Oklahoma. It is a relatively large play by areal extent and occupies parts of the Arkoma and Anadarko basins. The core counties delineated by cumulative production to date are illustrated in Figure 18. The top two counties have produced 41% of cumulative production, and the top five have produced 75%. The top counties are surrounded by others with generally lower well productivity.

[25] Energy Information Administration, "Natural Gas Weekly."

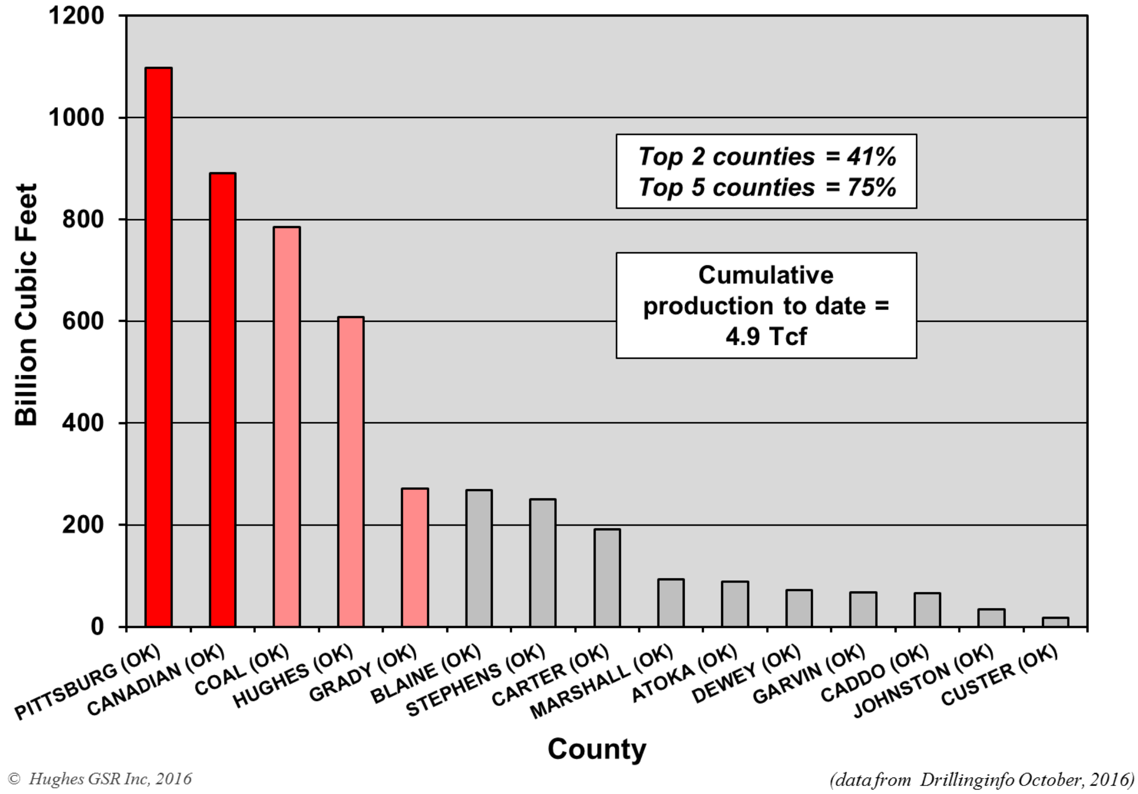


Figure 18. Woodford Play cumulative gas production by county through mid-2016.

The optimism bias of the EIA's AEO2016 Woodford reference case projection is rated as "high", given that it calls for producing 22% more gas by 2040 than the EIA's own estimate of "unproved technically recoverable resources" and 52% more over the 2014-2040 period than the "Most Likely" estimate of *Drilling Deeper*. Furthermore, the EIA projects that production will exit 2040 at all-time highs, implying that there are vast additional, presently unknown, resources that will be produced post-2040. The drilling rates required to do this would exhaust available drilling locations well before 2040 and would require higher prices than forecast by the EIA. Thus it is highly unlikely that this projection will be realized.

Some observations:

- More than 4,700 wells are now producing in the Woodford with approximately 14,000 drilling locations remaining for full development. Much of the recent drilling has focused on top counties, preferentially consuming the highest quality locations. This means that higher prices will be required to support drilling in the much larger portion of the play with poorer quality rocks, with correspondingly higher drilling rates to maintain, let alone grow, production.
- Producing well additions reached nearly 700 per year in mid-2014 (Figure 5) when Woodford production peaked. In order to grow production by 59% over current levels by 2040, as forecast by the EIA, drilling rates would have to grow to 900 per year or more, which would consume available drilling locations before 2035, setting the stage for a production collapse. There are, however, ample drilling locations remaining to sustain the Woodford on its current gradual production decline through 2040 as projected in *Drilling Deeper*.
- Although the Woodford has experienced a drop in rig activity, it has been much less than in other plays owing to the enthusiasm for the new "SCOOP" and "STACK" plays which produce gas mainly

in association with oil (total rig count fell from 79 in November 2011 to 45 in October 2016). This has cut the rate of producing well additions by 47% from peak rates in mid-2014 (Figure 5) and has resulted in a 13% drop in production from peak. Greater rig efficiencies, better technology, and the inventory of drilled but not completed wells (DUCs) has limited the impact on production and producing well additions somewhat from what it otherwise might have been. Nonetheless the EIA's AEO2016 forecast is unlikely to be realized.

2.7 BAKKEN PLAY

Figure 19 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 2.5% of all shale gas from 2014 to 2040, and 2.1% of 2040 production. The play peaked in March 2016 and was down 6% as of August 2016.[26] Gas production in the Bakken has increased significantly compared to oil in the past couple of years as the North Dakota government implemented new regulations to limit flaring, which previously was as high as 35% of production (flaring is now down to 10%).[27] Neither *Drilling Deeper* nor the EIA's AEO2016 took this into account in projecting future production, hence actual production is considerably higher than originally projected. The effect of a gradual decline in flaring from 30% in 2014 to 5% in 2018 is illustrated in Figure 19 and results in the recovery of nearly 2 Tcf of additional gas by 2040 over what was originally forecast in *Drilling Deeper*.

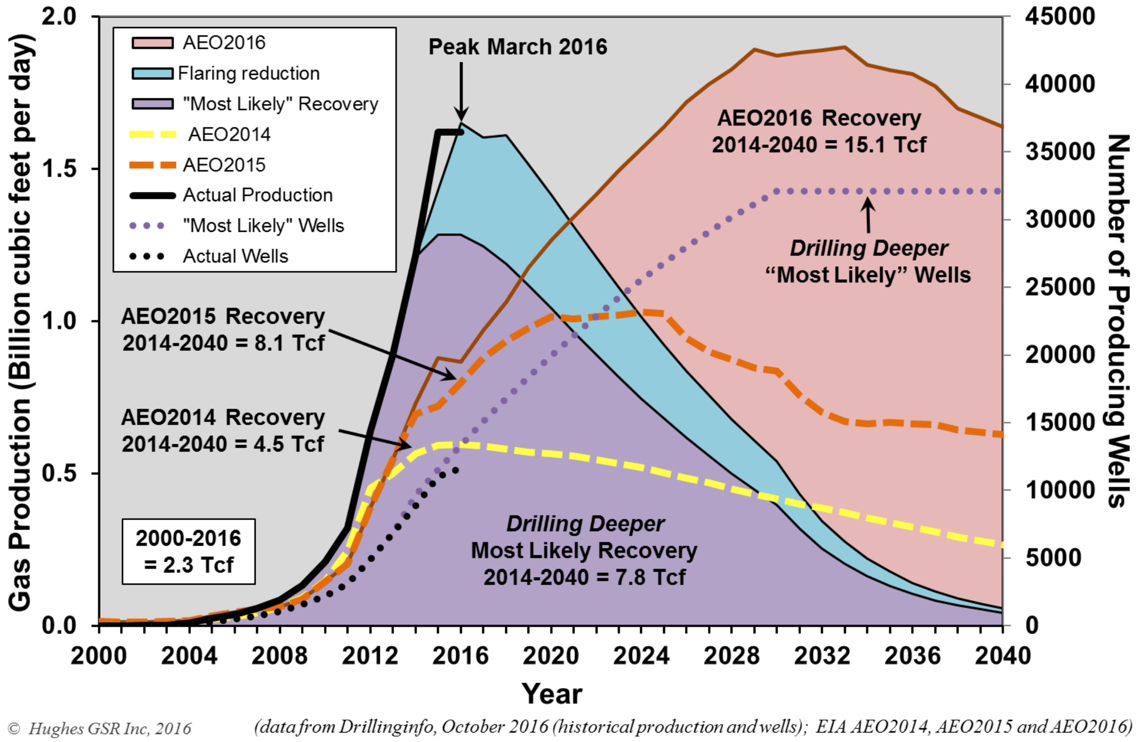


Figure 19. Bakken Play production for the "Most Likely" drilling rate forecast from *Drilling Deeper* compared to the EIA's AEO2014, AEO2015 and AEO2016 forecasts.

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. Cumulative production through mid-2016 was 2.3 Tcf. AEO2016 estimates cumulative recovery over the 2014-2040 period of 15.1 Tcf, compared to 7.8 Tcf in *Drilling Deeper* (including gas saved by reduced flaring). A reduction in flaring (shown in blue) accounts for the higher actual production than originally projected in *Drilling Deeper*.

The EIA has increased 2014-2040 recovery from the Bakken in AEO2016 to 15.1 Tcf, which is 87% (or 7 Tcf) higher than AEO2015, and 237% (or 10.6 Tcf) higher than AEO2014. It is also nearly double the *Drilling Deeper* estimate including additional gas that will be recovered due to flaring reduction. The EIA

[26] Energy Information Administration, "Natural Gas Weekly."

[27] Energy Information Administration, "Natural gas flaring in North Dakota has declined sharply since 2014," *Today in Energy*, June 13, 2016, https://www.eia.gov/todayinenergy/detail.php?id=26632.

AEO2016 estimate is also 27% larger than its own estimate of “unproved technically recoverable resources” as of January 1 2013 (Table 1).

The Bakken is the eighth largest U.S. shale gas play in terms of projected 2014-2040 recovery and is located mainly in North Dakota but also in the Elm Coulee field of eastern Montana. The core counties delineated by cumulative production to date are illustrated in Figure 20, and are the same core counties as for oil production. The top two counties have produced 57% of cumulative production, and the top five counties have produced 93%. The top counties are surrounded by several others with generally much lower well productivity.

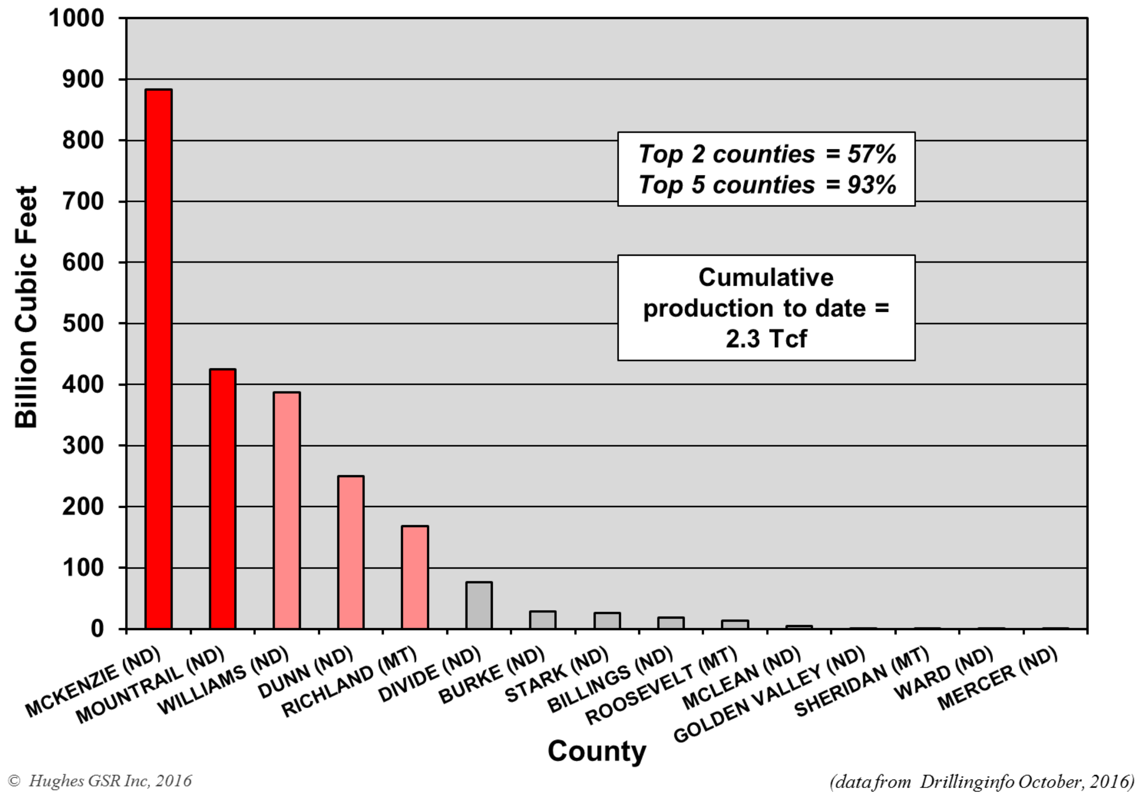


Figure 20. Bakken Play cumulative gas production by county through mid-2016.

The optimism bias of the EIA’s AEO2016 Bakken reference case projection is rated as “extremely high”, given that it calls for producing 27% more gas by 2040 than the EIA’s own estimate of “unproved technically recoverable resources” and nearly double the estimates of *Drilling Deeper*. Furthermore, the EIA projects that production will exit 2040 at higher than 2016 levels, implying that vast additional, presently unknown, resources will be produced post-2040. Gas is a secondary product in the Bakken as oil is the main focus, hence gas production will parallel oil production, for which I also rated the EIA’s AEO2016 estimate as having an extremely high optimism bias. The drilling rates required to meet the EIA’s oil forecast would exhaust drilling locations well before 2040, hence drilling locations to meet its gas forecast, which is related to oil drilling rates, are also likely to run out at the drilling rates required. Thus it is extremely unlikely that this projection will be realized.

Some observations:

- More than 11,600 wells are now producing in the Bakken with approximately 20,000 drilling locations remaining for full development. Much of the recent drilling has focused on top counties, preferentially consuming the highest quality locations. This means that higher prices will be required to support drilling in the much larger portion of the play with poorer quality rock, with correspondingly higher drilling rates to maintain, let alone grow, production.

- Producing well additions peaked at over 2,200 per year in early 2015 (Figure 5) just after Bakken oil production peaked. In order to nearly double oil production from its late-2014 peak, as forecast by the EIA, drilling rates would have to grow to 4,000 per year or more; this would consume available drilling locations before 2030, setting the stage for a production collapse, with gas production along with it. The new regulations in North Dakota to limit flaring have been very effective in bringing more gas to market, and delayed the gas peak by 16 months from the oil peak.
- The drop in rig counts in the Bakken (28 in October 2016 vs. 198 in October 2014) has cut the rate of producing well additions by two-thirds from peak rates in early 2015 (Figure 5) and has resulted in a peak and slight decline in gas production. The reduction in flaring, greater rig efficiencies, better technology, and the inventory of drilled but not completed wells (DUCs) has also limited the impact on production and producing well additions somewhat from what it otherwise might have been. Nonetheless the EIA's AEO2016 forecast is extremely unlikely to be realized.

2.8 "OTHER" PLAYS

Figure 21 illustrates the AEO2016 reference case forecast for "other" plays compared to AEO2015 and AEO2014. "Other" plays include the older Antrim play in Michigan and the emerging Utica play in Ohio, Pennsylvania and northern West Virginia. They account for 25.8% of projected 2014-2040 shale gas production in AEO2016 and make up 34.2% of 2040 production. According to the EIA's forecast, these plays will collectively constitute the biggest source of shale gas production in 2040, with production growing 369% from 2015 levels. The Utica, Antrim and other unnamed plays are forecast to account for 14%, 0.4% and 11.4%, respectively, of 2014-2040 shale gas production.

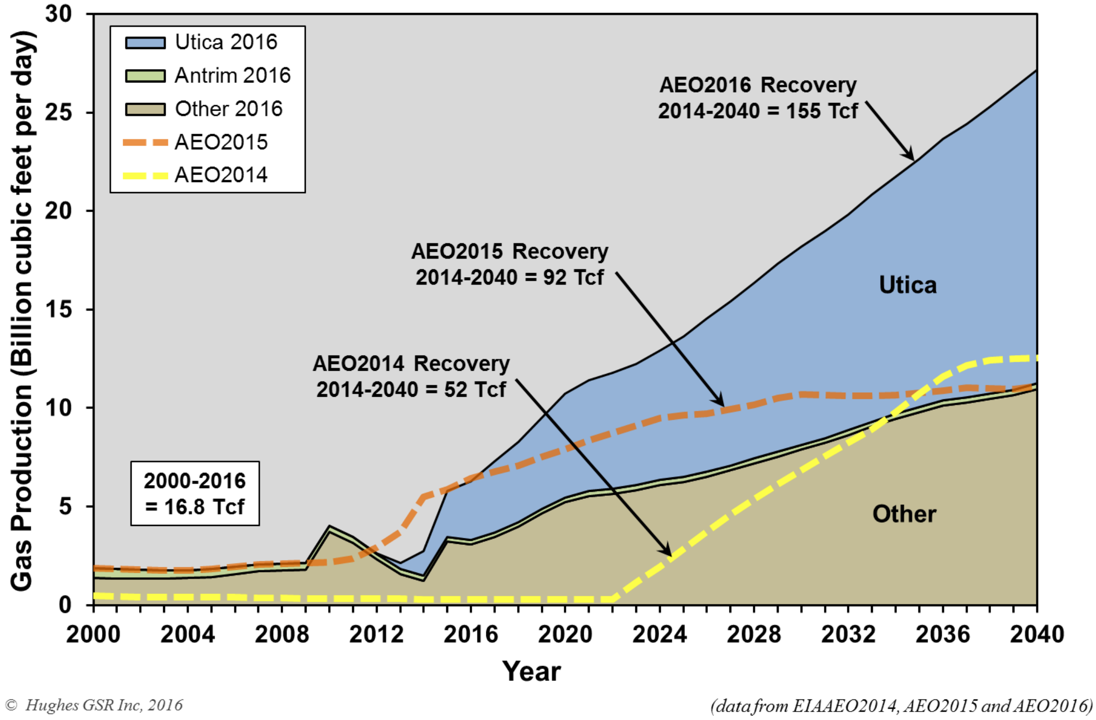


Figure 21. Other plays production in the AEO2016, AEO2015 and AEO2014 forecasts.

AEO2016 assumes an extremely aggressive production growth profile compared to the earlier projections. Cumulative production from these plays from 2000-2016 was 16.8 Tcf.

"Other" plays in AEO2016 are projected to recover 155 Tcf (or 69%) more than AEO2015 and 103 Tcf (or 200%) more than AEO2014.The AEO2016 production projection is very aggressive. The Utica is forecast to grow to the level of the current production of the Marcellus by 2040, an increase of 578% over 2015 levels (the Utica recently peaked in February 2016[28]). Other unnamed plays are forecast to grow by 239% over the same period. The Antrim, long in decline, is forecast to grow 38%. All this is projected to happen at relatively low prices (Figure 2). Notwithstanding that the Utica has upward growth potential if prices rise and drilling rates grow, the optimism bias of "other" plays in AEO2016 is rated as "very high".

Exceptional shale gas plays are clearly not ubiquitous; the seven major plays reviewed in this report, plus the Utica, account for 88% of projected 2014-2040 shale gas production in AEO2016, and the Marcellus and Haynesville alone account for 51%. All "other" established and emerging plays in the U.S., even allowing for the EIA's optimism, account for just 12%.

[28] Energy Information Administration, "Natural Gas Weekly."

3 All Plays Comparison

Table 2 summarizes, by play, the production projections in AEO2016 and the optimism bias ratings I have assigned them. The optimism bias rating takes into consideration: play fundamentals such as average well productivity trends, decline rates, play area and number of available drilling locations; total projected recovery through 2040 compared to the EIA's estimate of "unproved technically recoverable resources"; and the exit level of production in 2040, which indicates the amount of additional resources implied to be recovered post-2040. Although the Eagle Ford play has a "moderate" optimism bias rating, four plays accounting for 60% of projected 2014-2040 production are rated at "extremely high", and the overall optimism bias of AEO2016 is rated as "very high".

Play	2014-2040 production (Tcf)	% of 2014-2040 production	% of 2040 production	EIA Optimism Bias
Marcellus	214.8	35.6%	30.7%	Extremely high
Haynesville	91.8	15.2%	15.7%	Extremely high
Eagle Ford	35.0	5.8%	3.0%	Moderate
Barnett	41.2	6.8%	6.9%	Extremely high
Fayetteville	25.5	4.2%	3.7%	High
Woodford	24.3	4.0%	3.7%	High
Bakken	15.1	2.5%	2.1%	Extremely high
Other	155.2	25.7%	34.2%	Very high
Total	**603.0**	**100%**	**100%**	**Very high**

Table 2. Projected shale gas recovery from 2014 to 2040, percent of 2040 production, and optimism bias for AEO2016 plays assessed in this report.

Note that "other" includes the Antrim and Utica plays as listed in Table 1.

Figure 22 illustrates the aggregate production for the seven major plays analyzed in the *Drilling Deeper* "Most Likely" case compared to forecasts for the same plays from AEO2016, AEO2015 and AEO2014. AEO2016 production from 2014 to 2040 is 81 Tcf (or 22%) higher than AEO2015, and 203 Tcf (or 83%) higher, than *Drilling Deeper*. A large part of the net increase in cumulative production between AEO2016 and AEO2015 is a result of the EIA's extremely optimistic revision of the Marcellus and Haynesville, and its aggressive growth forecast for the Utica.

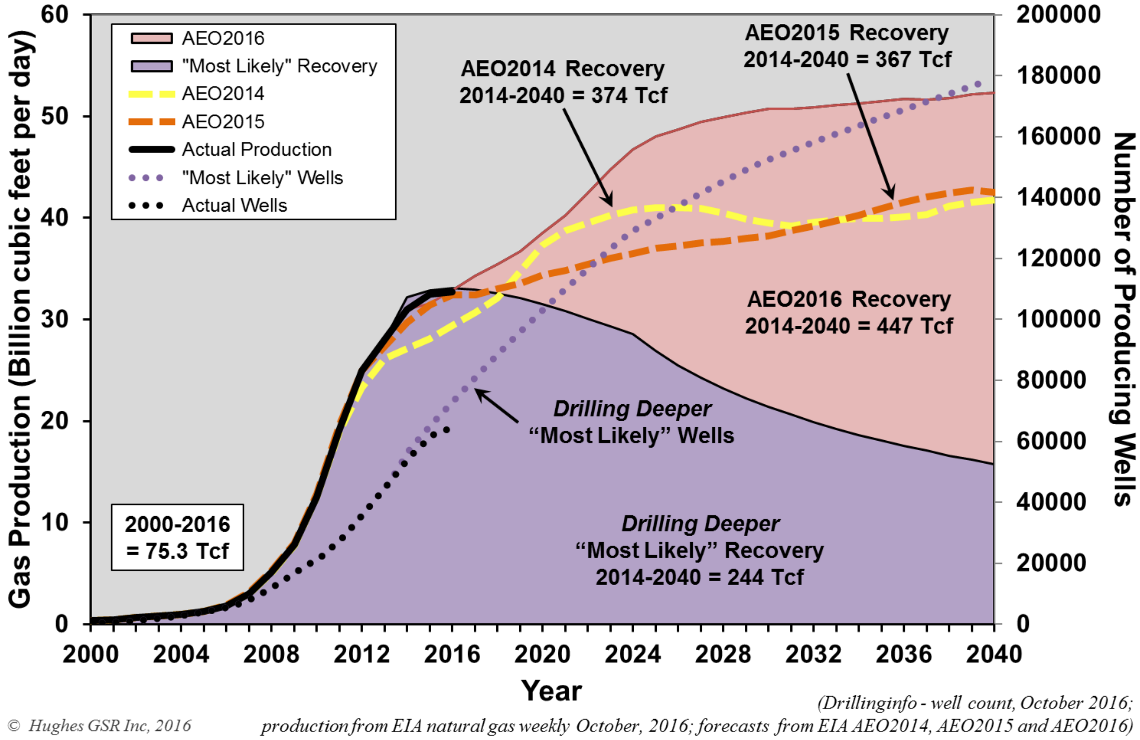


Figure 22. Comparison of the AEO2016 projection to AEO2014 and AEO2015 for the seven major plays analyzed herein compared to the "Most Likely" forecast for these plays in *Drilling Deeper*.

Actual production, which has amounted to 75.3 Tcf through mid-2016, is also shown. *Drilling Deeper* projected the recovery of 244 Tcf for 2014-2040 compared to the AEO2016 estimate of 447 Tcf, some 83% higher. These plays comprise 74% of projected 2014-2040 recovery.

The AEO2016 projections represent a very good news story for those hoping for a lasting shale gas boom with relatively low gas prices. Total 2014-2040 shale gas recovery projections (including "other" plays) are up 144 Tcf, or 31%, from AEO2015. Unfortunately, the AEO2016 projections are highly unlikely to be realized based on an analysis of play fundamentals and the advancing state of drilling maturity for most plays.

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 shale gas plays are now relatively well known and don't change wildly from year to year. Although average well productivity has increased in some plays in the last two years it has remained flat or 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 shale gas recovery. Figure 23 illustrates the magnitude of production rate differences between AEO2015 and AEO2016 by play and year in percentage terms. All plays have been revised upward with the exception of the Eagle Ford and early years in the Fayetteville and Barnett—in some plays/years by more than 60%. Shale gas production overall has been revised upward in all years, with revisions exceeding 30% after 2025 and reaching 50% in 2040.

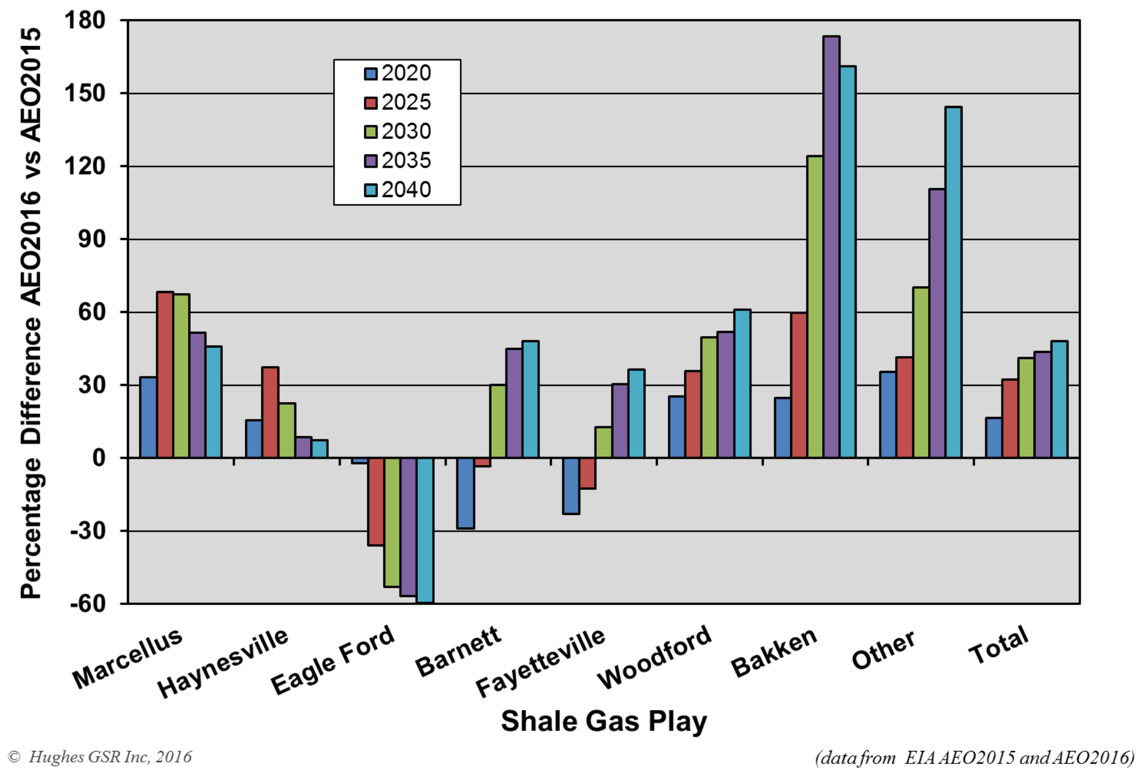


Figure 23. Comparison of production projections by play from AEO2016 and AEO2015.

Comparisons are made in terms of the percentage difference in production rates in AEO2016 and AEO 2015 for the years 2020, 2025, 2030, 2035 and 2040. All years have increased in terms of total projected production; in the case of 2025 to 2040, by more than 30%.

Figure 24 illustrates the changes in total gas 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 Marcellus, Haynesville, Woodford, Bakken and “other” plays resulted in a total increase in projected production of 144 Tcf, or 31% more in AEO2016 than AEO2015. Downward revisions occurred in the Eagle Ford and Fayetteville of 33% and less than 1%, respectively.

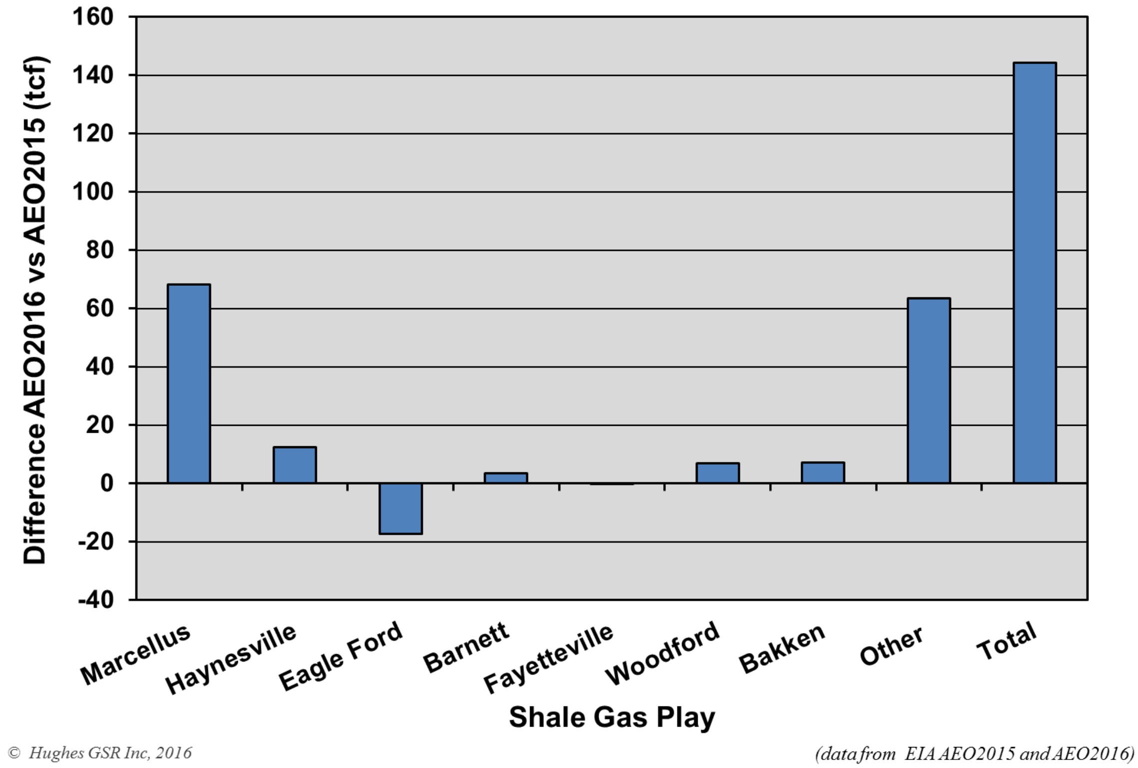


Figure 24. Comparison of projections by play from AEO2016 and AEO2015 in terms of total gas production from 2014 to 2040.

Overall production has increased by 144 Tcf, or 31%, 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 sweet spot counties of major plays (like the Bakken, Eagle Ford and Marcellus[29]) as expected as sweet spots are drilled off. The increase in production cannot be attributed to changes in future gas price assumptions either, given that prices are 20% lower in AEO2016 than AEO2015 ($6.03/MMbtu average over 2020-2040 in AEO2015 vs $4.86/MMbtu in AEO 2016).

The volatility and optimism in EIA play-level shale gas 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.

[29] See J. David Hughes, “Revisiting the Shale Oil Hype: Technology versus Geology”, Post Carbon Institute, March 30, 2015, http://www.postcarbon.org/revisiting-the-shale-oil-hype-technology-versus-geology/ and J. David Hughes, “Marcellus Production Outlook,” Post Carbon Institute, April 28, 2015, http://www.postcarbon.org/marcellus-production-outlook/.

4 Summary and Implications

Shale gas production overall has declined by 4.7% since peaking in February 2016 (down 2.1 billion cubic feet per day; see Table 3). All shale plays have peaked and older plays, like the Barnett and Haynesville, are down 38% and 52%, respectively. When *Drilling Deeper* was published two years ago most plays were in ascent and rig counts were at all-time highs. 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 shale gas plays are not ubiquitous, as some would have us believe. Just five plays, the Marcellus, Eagle Ford, Utica, Haynesville and Barnett, made up 74% of August 2016 production.

Play	Peak date	Decline from peak (bcf/day)	% below peak as of August 2016	% of total production as of August 2016	EIA Optimism Bias (Hughes)
Marcellus	Feb-16	0.688	4.0%	39.2%	Extremely high
Haynesville	Jan-12	3.775	52.4%	8.2%	Extremely high
Eagle Ford	Sep-15	0.839	16.6%	10.0%	Moderate
Barnett	Nov-11	1.892	37.8%	7.4%	Extremely high
Fayetteville	Nov-12	0.952	32.8%	4.6%	High
Woodford	Aug-14	0.294	13.1%	4.7%	High
Bakken	Mar-16	0.067	6.5%	2.3%	Extremely high
Utica	Feb-16	0.135	3.6%	8.7%	Very high
Antrim	Mar-00	0.258	52.5%	0.6%	Very high
Rest of US	Apr-16	0.148	2.4%	14.3%	Very high
Total	**Feb-16**	**2.072**	**4.7%**	**100.0%**	**Very high**

Table 3. Peak, decline, and EIA optimism bias of shale gas plays.[30]

Peak and production data are from EIA's *Natural Gas Weekly* report, which estimates production for recent months. Note, however, that the latest available actual production data used in the play analyses in this report are from Drillinginfo as of June 2016.

[30] Energy Information Administration, "Natural Gas Weekly."

Future production of shale gas 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: Shale gas 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 shale gas plays, and new technology has not changed that.[31]

With regard to technology: the fossil fuel industry has responded to the challenge of low 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.[32] A review of well costs and trends for the Marcellus reveals that, compared to 2006, well lateral length has increased to 7,000 feet from 5,000 feet, fluid used has increased many-fold to 8.7 million gallons per well, and proppant used has increased 10-fold to nearly 10 million pounds per well[33] (Chesapeake recently reported using 50 million pounds of proppant on a Haynesville well).[34] Similar trends are evident in other plays. This has improved individual well production, but as each well can now drain more of the reservoir it has also 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. But there are a limited number of drilling locations in sweet spots, and high grading plus the downturn in prices has resulted in their exhaustion at disproportionately high rates, leaving higher-cost gas for later. An analysis of top counties in plays like the Marcellus and Eagle Ford shows that average well productivity has begun to decline, meaning that the best locations are being exhausted along with possible well interference (from wells being drilled too close together).

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[31] 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.

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

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

[34] Joe Carroll and David Wethe, "Chesapeake Energy Declares 'Propageddon' With Record Frack."

My "very high" optimism bias rating for the overall EIA AEO2016 reference case shale gas projections 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 25, which shows that the EIA assumes that production will begin to grow strongly starting in 2017, despite a 37% decline in drilling rate from peak levels in 2014. Tight oil and shale gas production are collectively forecast to grow 88% from 2014 levels to all-time highs by 2040, while drilling rates remain below 2014 levels to 2040, with only a modest increase in price.

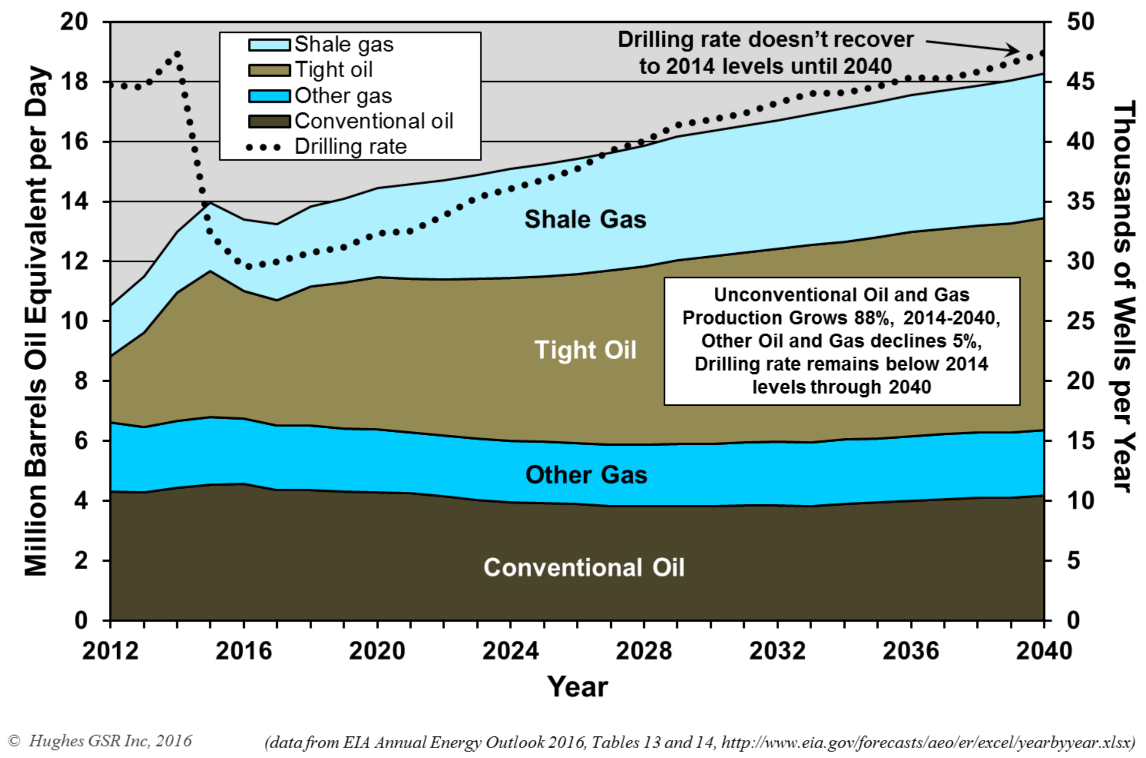

Figure 25. Growth in oil and gas production versus estimated drilling rates for the AEO2016 reference case projection.

The EIA drilling rates in Figure 25 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."[35]

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 Marcellus shale gas production rise 48% from current levels, recover 47% more gas than the EIA's estimate of "unproved technically recoverable resources", and exit 2040 at near all-time high production levels? How can the Haynesville grow 223% from current levels and exit 2040 at all-time high production levels after recovering 28% more gas than the EIA's estimate of unproved resources? How can an old play like the Barnett be resurrected and exit 2040 at near all-time high production levels after recovering 145% more unproved resources than the EIA

[35] 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.

estimates exist? How can overall shale gas production increase by 31% in AEO2016 compared to AEO2015 while assuming gas prices are 20% lower over the 2015-2040 period?

The EIA's projections for shale gas 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. Major investments are being made in gas-fired generation on the assumption that gas will be abundant and cheap for the foreseeable future. LNG export terminals have been built and more are under construction to export the projected bounty of cheap gas. These investments lock in demand regardless of future supply shortfalls and price spikes. Getting it wrong has serious implications for energy policy and future energy security. This analysis shows that the EIA has erred on the side of extreme optimism in its shale gas production forecasts which are highly unlikely to be realized.