

# DRILLING DEEPER

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

## PART 3: SHALE GAS



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# PART 3: SHALE GAS



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## 3.1 INTRODUCTION

### 3.1.1 Overview

The widespread adoption of hydraulic fracturing (“fracking”) and horizontal drilling in the United States to extract oil and natural gas from previously inaccessible shale formations has been termed the “shale revolution.” U.S. natural gas production, thought to be in terminal decline as recently as 2005, has exceeded its all-time 1973 peak. The U.S. Energy Information Administration (EIA) now projects domestic gas production to reach nearly 38 trillion cubic feet per year by 2040, which is 55% above 2013 levels.

Although the U.S. is still a net importer of gas from Canada, there is now a rush to export natural gas overseas. Four liquefied natural gas (LNG) export terminals have been approved—one of which is under construction at Sabine Pass in Louisiana—with a further 13 “proposed” and an additional 13 under consideration as “potential”.<sup>1</sup> The enthusiasm for LNG exports is based on the assumption that the North American gas supply will continue to grow for the foreseeable future and prices will remain low, resulting in an attractive differential with much higher gas prices in Europe and Asia.

The environmental, health, and quality of life impacts of shale development have stoked controversy across the country. In contrast, the expectation of long-term domestic natural gas abundance—driven by optimistic forecasts from industry and government—has been widely reported and little questioned, despite the myriad economic and policy consequences. There is no question that the development of shale gas has created a surge in production. However, a look at the fundamentals of shale plays reveals that they come with serious drawbacks, both in terms of environmental impact and the sustainability of long term production.

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

The analysis shows that maintaining U.S. shale gas production, let alone increasing production at rates forecast by the EIA through 2040, will be problematic. Four of the top seven shale gas plays are already in decline. Of the major plays, only the Marcellus, along with associated gas from the Eagle Ford and Bakken tight oil plays, are increasing—and yet, the EIA reference gas forecast calls for plays currently in decline to grow to new production highs, at moderate future prices. Lesser plays like the Utica and others are also counted on for strong growth. Although significantly higher gas prices needed to justify higher drilling rates could temporarily reverse decline in some of these plays, the EIA forecast is unlikely to be realized.

The analysis also underscores the amount of drilling, the amount of capital investment, and the associated scale of environmental and community impacts that will be required to meet these projections. These findings call into question plans for LNG exports and highlight the real risks to long-term U.S. energy security.

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<sup>1</sup> FERC, July 18, 2014, “LNG,” <http://www.ferc.gov/industries/gas/indus-act/lng.asp>.

### 3.1.2 Methodology

This report analyzes the top five U.S. shale gas plays—the Barnett, Haynesville, Fayetteville, Woodford and Marcellus—as well as associated gas production from the top two tight oil plays, the Bakken and Eagle Ford. Together these plays make up 88% of shale gas production through 2040 in the EIA’s 2014 Annual Energy Outlook (AEO 2014).

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

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

1. **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.
2. **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.
3. **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 frack treatments have increased well productivity in the early stages of the development of all plays, they have provided diminishing returns over time, and cannot compensate for poor quality reservoir rock.
4. **Number of potential wells:** Plays are limited in area and therefore have a finite number of locations to be drilled. Once the locations run out, production goes into terminal decline.
5. **Rate of drilling:** The rate of production is directly correlated with the rate of drilling, which is determined by the level of capital investment.

The basic methodology used is as follows:

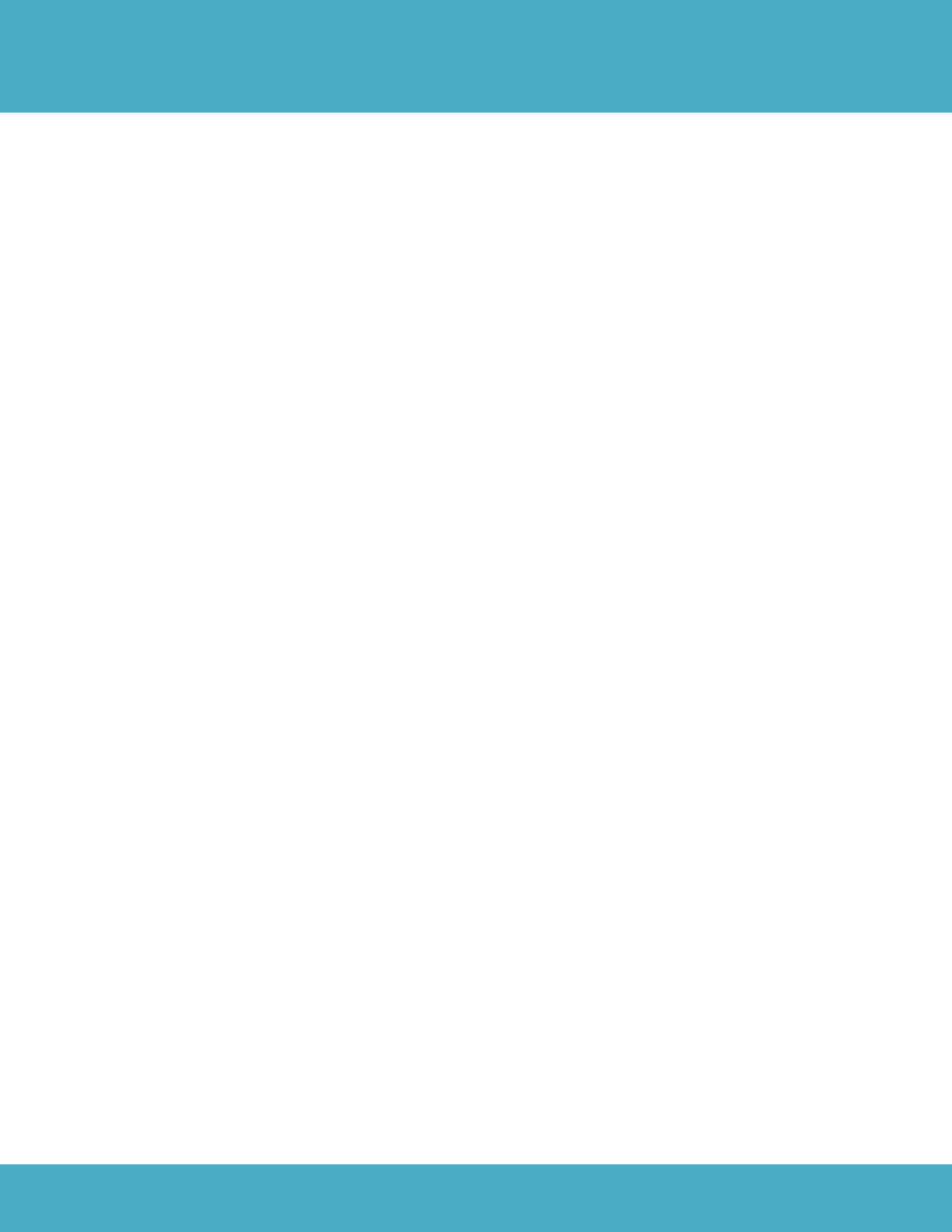
- Historical production, number of currently producing wells and total wells drilled, the split between horizontal and vertical/directional wells, and the overall play area were determined for all plays. Average well decline for wells, both horizontal and vertical/directional, and the average estimated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

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<sup>2</sup> See <http://info.drillinginfo.com>.

- First-year average production was established from type decline curves (i.e., average well decline profiles) constructed for all wells drilled in the year in question; 2013 was the year used as representative of future average first-year production levels per well. Average first-year production is used to determine the number of wells needed to offset field decline each year, and to determine the production trajectory over time given various drilling rates. In determining future production rates, the current trends in well productivity over time were considered; for example if recent well quality trends were increasing, it was assumed for plays in early stages of development that well quality would increase somewhat in the future before declining as drilling moves into lower quality outlying portions of plays.
- Projections of future production profiles were made for all plays based on various drilling rate scenarios. These projections assume a gradation over time from the well quality observed in the current top counties of a play to the well quality observed in the outlying counties as available drilling locations are used up. The different drilling rate scenarios were prepared so that the effect of a high drilling rate, presumably due to favorable economic conditions, compared to a low or a “Most Likely” drilling rate, could be assessed, both in terms of production over time and cumulative gas recovery from the play by 2040.
- Production projections and the production history and cumulative production for all plays were then compared to the EIA forecasts to assess the likelihood that these forecasts could be met.
- All plays were then compared to each other in terms of well quality and other parameters and an overall assessment of the likely long-term sustainability of shale gas production was determined.

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

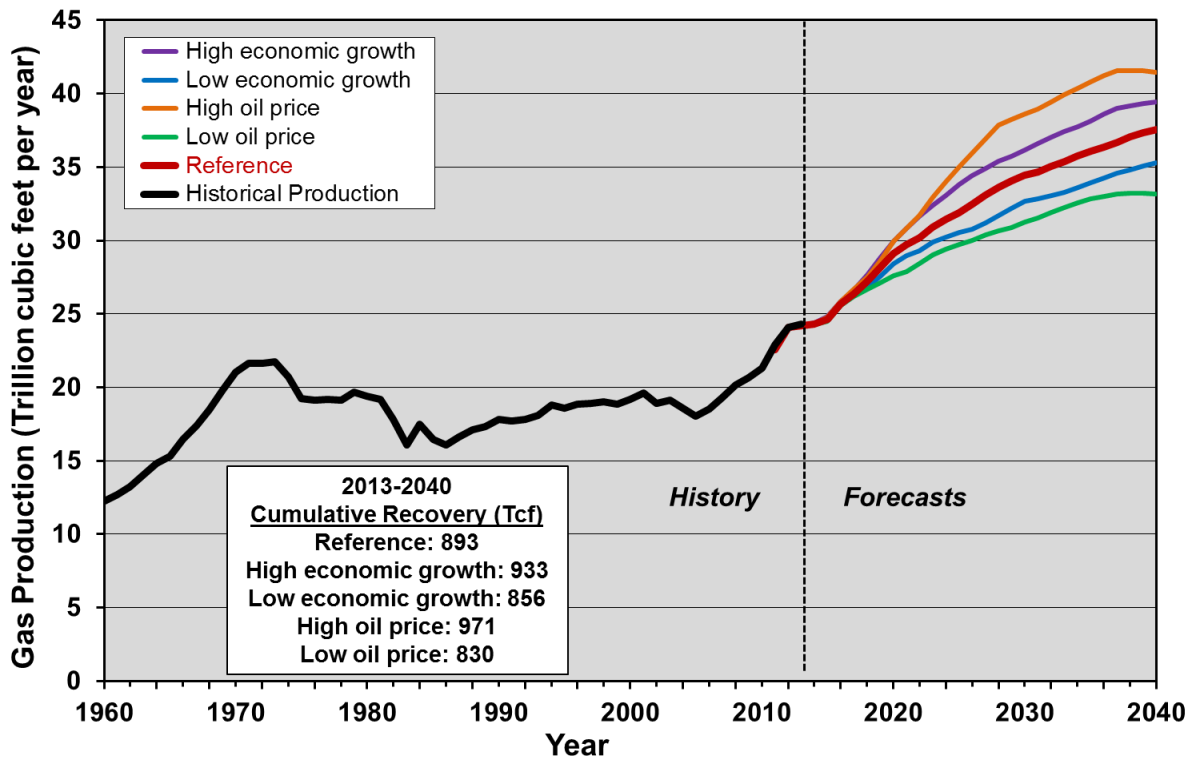


## 3.2 THE CONTEXT OF U.S. GAS PRODUCTION

### 3.2.1 U.S. Gas Production Forecasts

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

Figure 3-1 illustrates the range of the EIA's gas production forecasts through 2040 compared to historical production. These scenarios project U.S. gas production to rise anywhere from 37% to 71% above 2013 levels by 2040 and recover between 856 and 971 trillion cubic feet of gas over the 2013-2040 period. This amounts to 2.5-2.9 times the proved reserves that existed as of 2012<sup>3</sup> (proved reserves are generally considered to be economically recoverable with current technology). Adding in unproved resources, which are uncertain estimates without price constraints, between 37% and 42% of remaining potentially recoverable gas in the U.S. will be consumed over the next 26 years according to the EIA projections. This amounts to the equivalent of 85% to 99% of all the gas produced over the 54 years between 1960 and 2013.



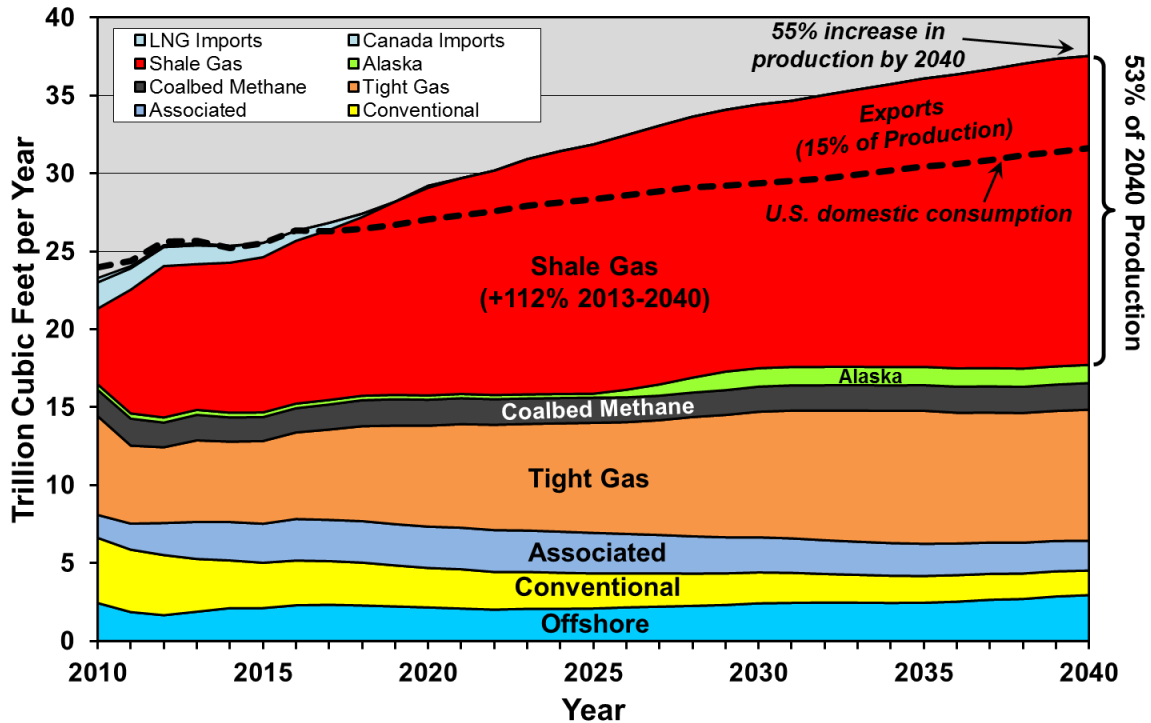
**Figure 3-1. Scenarios of U.S. gas production through 2040 from the EIA's Annual Energy Outlook 2014<sup>4</sup> compared to historical production from 1960.**

<sup>3</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>4</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo>.



The source of this optimism in future gas production is the application of high-volume, multi-stage, hydraulic fracturing technology (“fracking”) in horizontal wells, which has unlocked previously inaccessible gas trapped in highly impermeable shales. Figure 3-2 illustrates the EIA’s reference case gas production projection by source through 2040. Although conventional production is forecast to be flat or grow only slightly over the period, shale gas is forecast to more than double from 2013 levels and be 53% of a much expanded supply by 2040. Gas prices in this reference case are forecast to remain below \$5 per million Btu (MMBtu) (2012 dollars) through 2024 and \$6/MMBtu through 2030. Some 15% of production is forecast to be available for LNG and other exports in 2040, and net imports from Canada will cease by 2018.

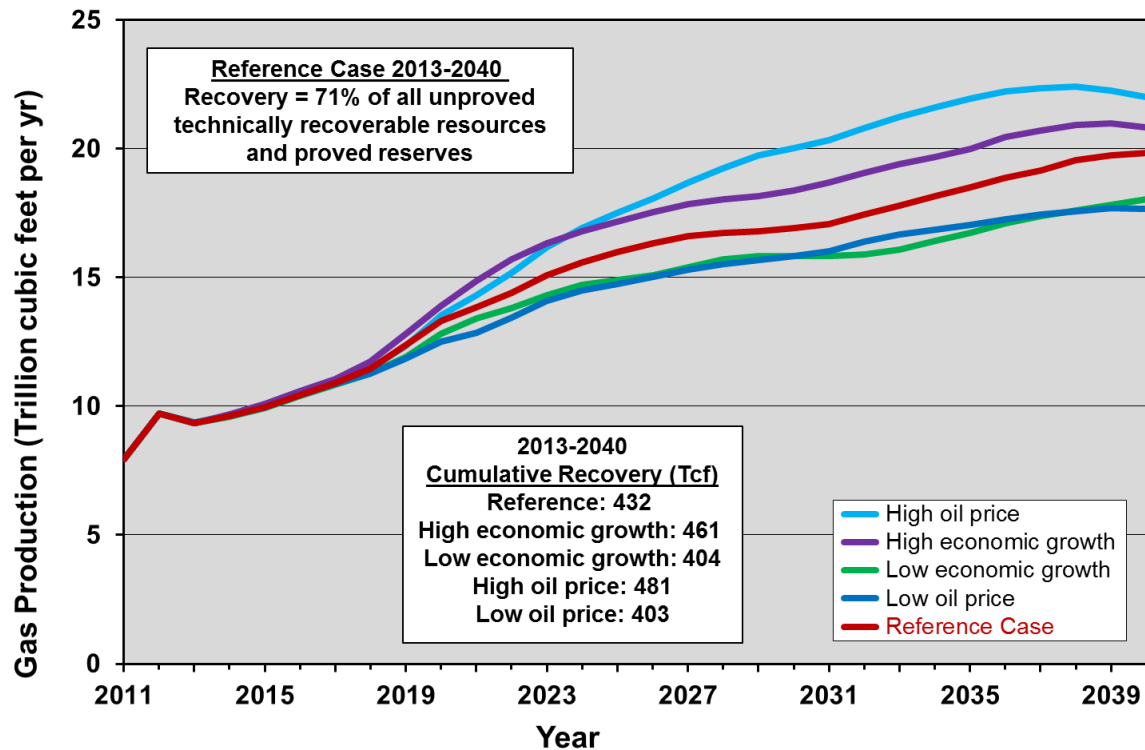


**Figure 3-2. EIA reference case forecast of U.S. natural gas production by source through 2040.<sup>5</sup>**

Overall production increases 55% from 2013 to 2040, whereas shale gas increases 112% over the same period.

<sup>5</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo>.

Figure 3-3 illustrates EIA forecasts for shale gas production in several cases. These assume the extraction of between 66% and 79% of the EIA's estimated 611 trillion cubic feet of proved shale gas reserves and unproved resources by 2040<sup>6</sup> (unproved resources have no implied price required for extraction and are highly uncertain compared to proved reserves which are recoverable with current technology under current economic conditions).



**Figure 3-3. EIA scenarios of U.S. shale gas production through 2040.<sup>7</sup>**

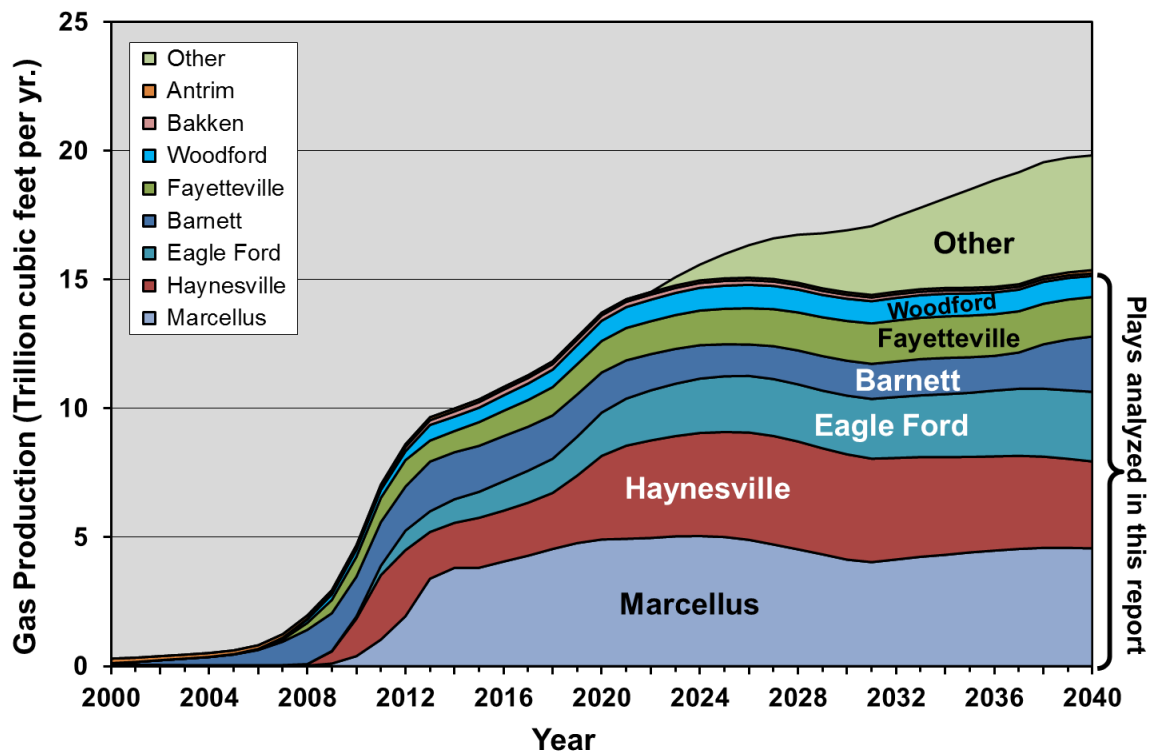
Unproved technically recoverable resources are estimated by the EIA at 489 trillion cubic feet and proved reserves at 122 trillion cubic feet<sup>8</sup>, so these scenarios amount to the recovery of 66% to 79% of all proved reserves and unproved resources by 2040.

<sup>6</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo>.

<sup>7</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo>.

<sup>8</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

Figure 3-4 illustrates how the EIA reference case projections for shale gas production are divided between plays.



**Figure 3-4. EIA reference case forecast of shale gas production divided by play through 2040.<sup>9</sup>**

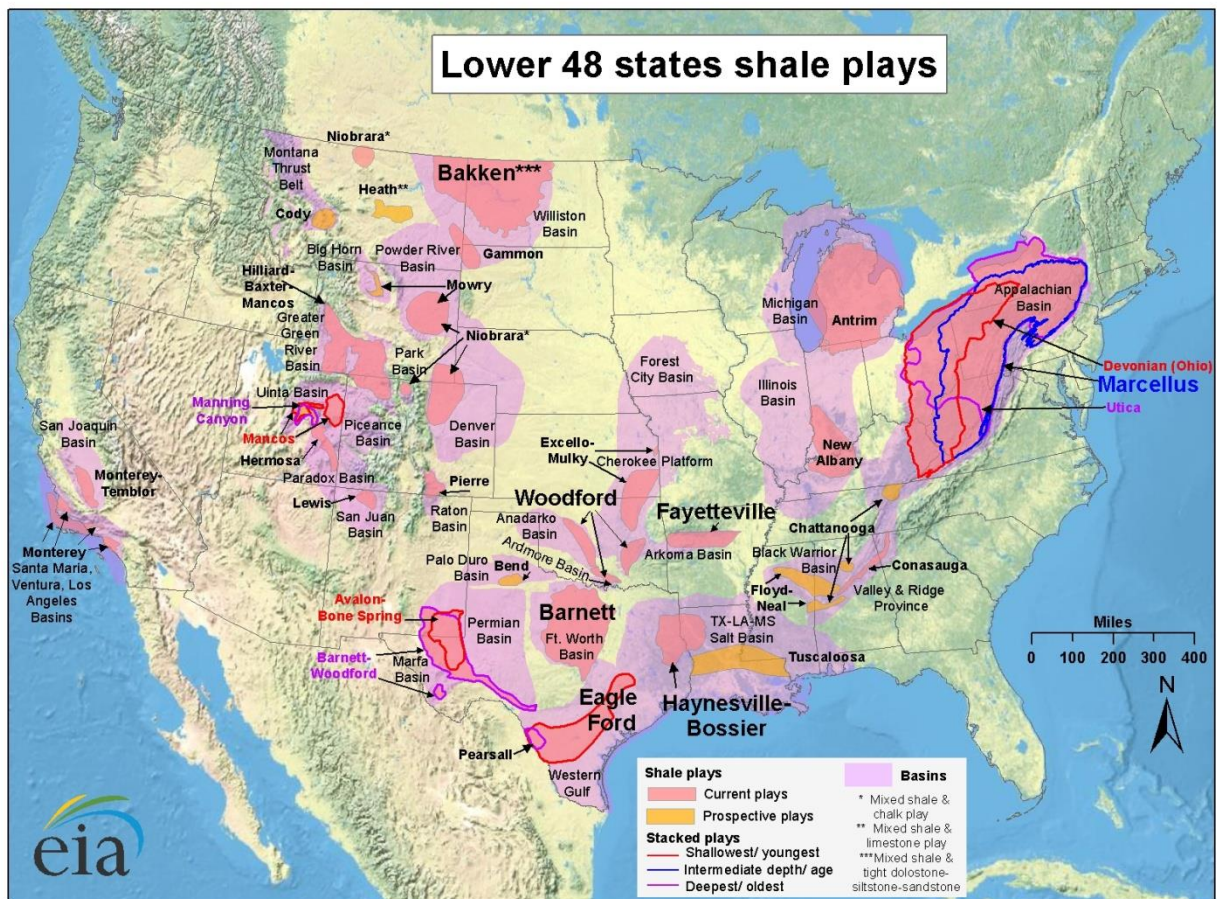
This report analyzed the seven most productive plays, which account for 88% of EIA's reference case shale gas production forecast to 2040.

The EIA reference case clearly expects the seven shale gas plays analyzed in this report to provide the bulk of production through 2040, with “other” plays increasing significantly after 2020. Shale gas production in all these plays has risen quickly due to rapid increases in drilling rates and sustained high levels of capital input; however, four of them are now in decline. High well- and field-decline rates, coupled with a finite number of drilling locations, suggest that production will be problematic to sustain, let alone grow at these forecast rates. Section 3 of this report explores the realistic production potential for these plays in depth.

<sup>9</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

### 3.2.2 Current U.S. Shale Gas Production

Production of shale gas began in the Barnett play of eastern Texas in the late 1990s and early 2000s. With the widespread application of horizontal drilling and hydraulic fracturing (“fracking”) beginning in 2003, production grew rapidly. The Haynesville play of Louisiana and east Texas was unknown as recently as 2007, and became the largest shale play in the U.S. at its peak in late 2011—although production has subsequently declined by 46%. The distribution of shale plays in the U.S. lower 48 states is illustrated in Figure 3-5.



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

Figure 3-5. Distribution of lower 48 states shale gas and oil plays.<sup>10</sup>

<sup>10</sup> EIA, “Shale Gas and Oil Plays, Lower 48 States,” [http://www.eia.gov/pub/oil\\_gas/natural\\_gas/analysis\\_publications/maps/maps.htm](http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm).

Current production from U.S. shale gas plays is estimated by the EIA at 37 billion cubic feet per day. Despite the apparent widespread nature of shale plays in Figure 3-5, nearly half of this production comes from just two plays—the Barnett and the Marcellus—and 78% comes from just five plays. Figure 3-6 illustrates shale gas production by play from 2000 through August 2014 according to the EIA.

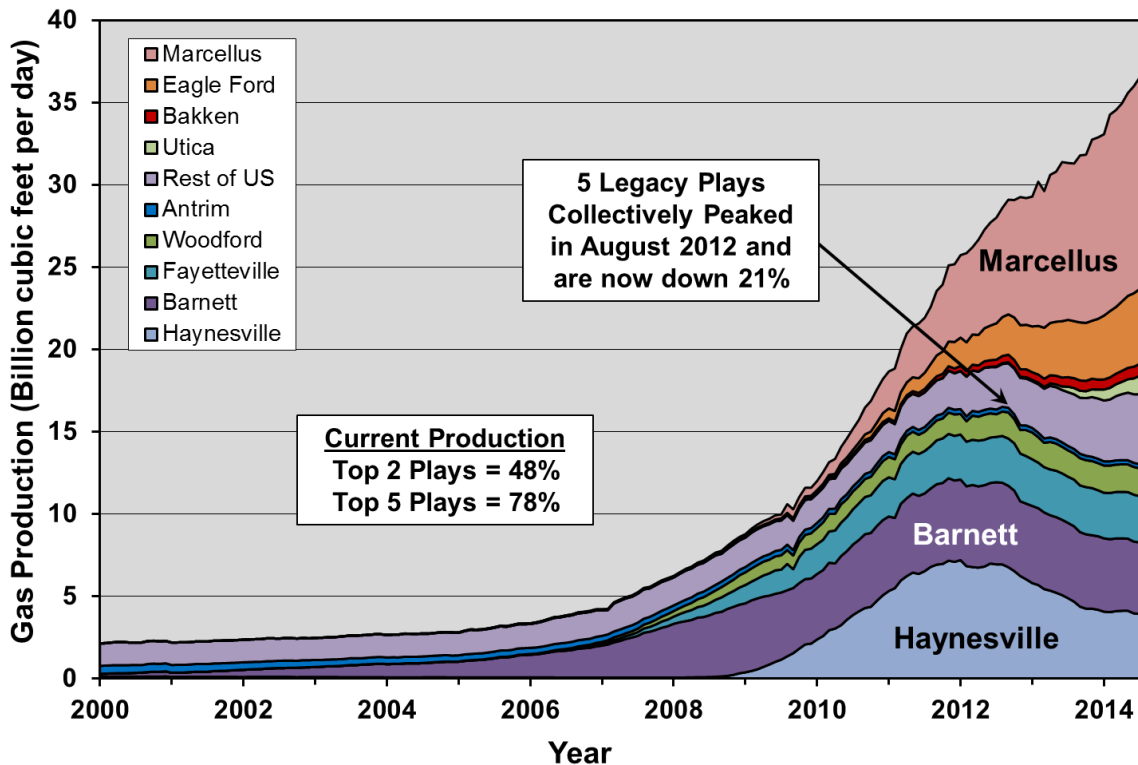


Figure 3-6. U.S. shale gas production by play from 2000 through July 2014, according to the EIA.<sup>11</sup>

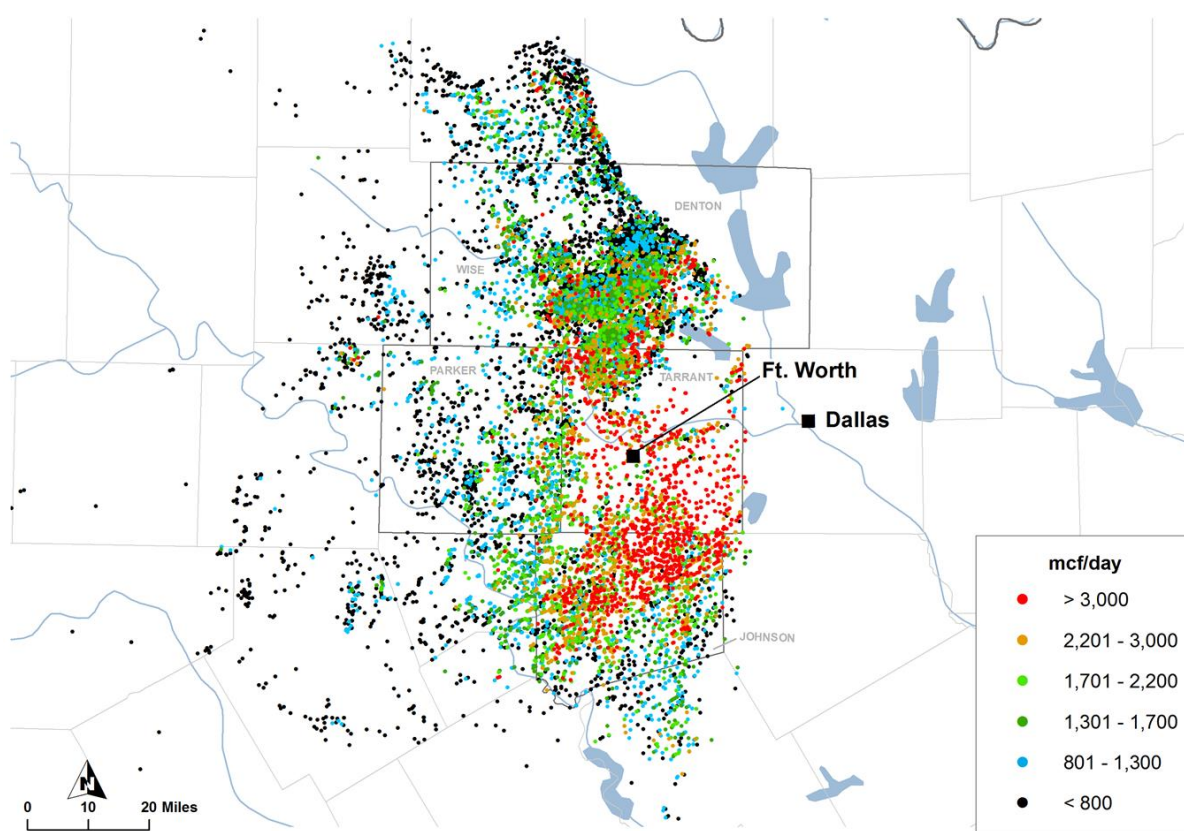
<sup>11</sup> EIA estimates obtained in October 2014 from <http://www.eia.gov/naturalgas/weekly>.

## 3.3 MAJOR U.S. SHALE GAS PLAYS

### 3.3.1 Barnett Play

The EIA forecasts recovery of 53 Tcf of gas from the Barnett play by 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Barnett play is where shale gas production got its start in the late 1990s and the combination of horizontal drilling with multi-stage hydraulic fracturing (“fracking”) was first applied at scale. Shale fracking was commercialized here by Mitchell Energy, a company headed by the late George Mitchell, “the father of fracking.”<sup>12</sup> Figure 3-7 illustrates the distribution of wells as of early 2014. Over 19,600 wells have been drilled to date of which 15,906 were producing at the time of writing. The play covers parts of 24 counties although most of the drilling is concentrated in five counties in east Texas surrounding the city of Dallas/Fort Worth.



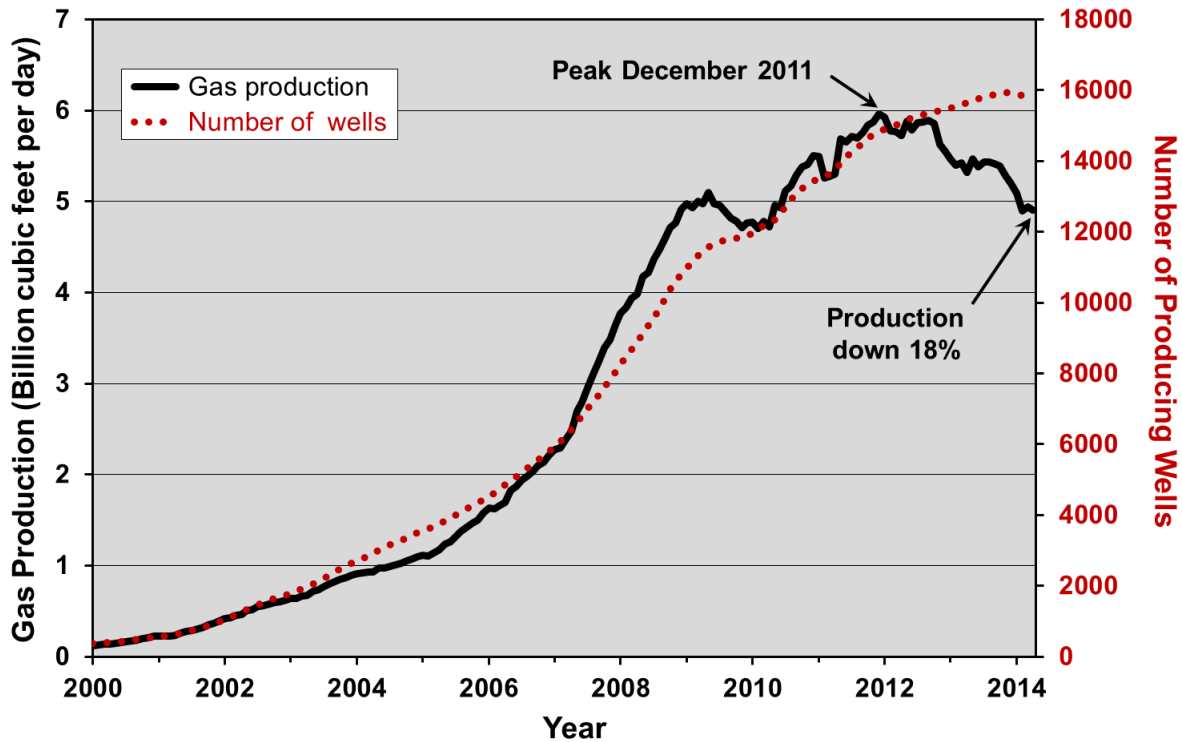
**Figure 3-7. Distribution of wells in the Barnett play as of early 2014, illustrating highest one-month gas production (initial productivity, IP).<sup>13</sup>**

Well IPs are categorized approximately by percentile; see Appendix.

<sup>12</sup> *The Economist*, August 3, 2013, “The father of fracking,” <http://www.economist.com/news/business/21582482-few-businesspeople-have-done-much-change-world-george-mitchell-father>.

<sup>13</sup> Data from Drillinginfo retrieved August 2014.

Production in the Barnett peaked at nearly six billion cubic feet per day in December 2011 as illustrated in Figure 3-8. Ninety-four percent of current production is from horizontal fracked wells. The rate of drilling grew from about 500 (mainly vertical) wells per year in 2002 to a peak of over 2,800 (mainly horizontal) wells per year in 2008. It has since fallen to about 400 wells per year which is insufficient to offset field decline. Drilling rates required to keep production flat at current production levels are about 1,161 wells per year.

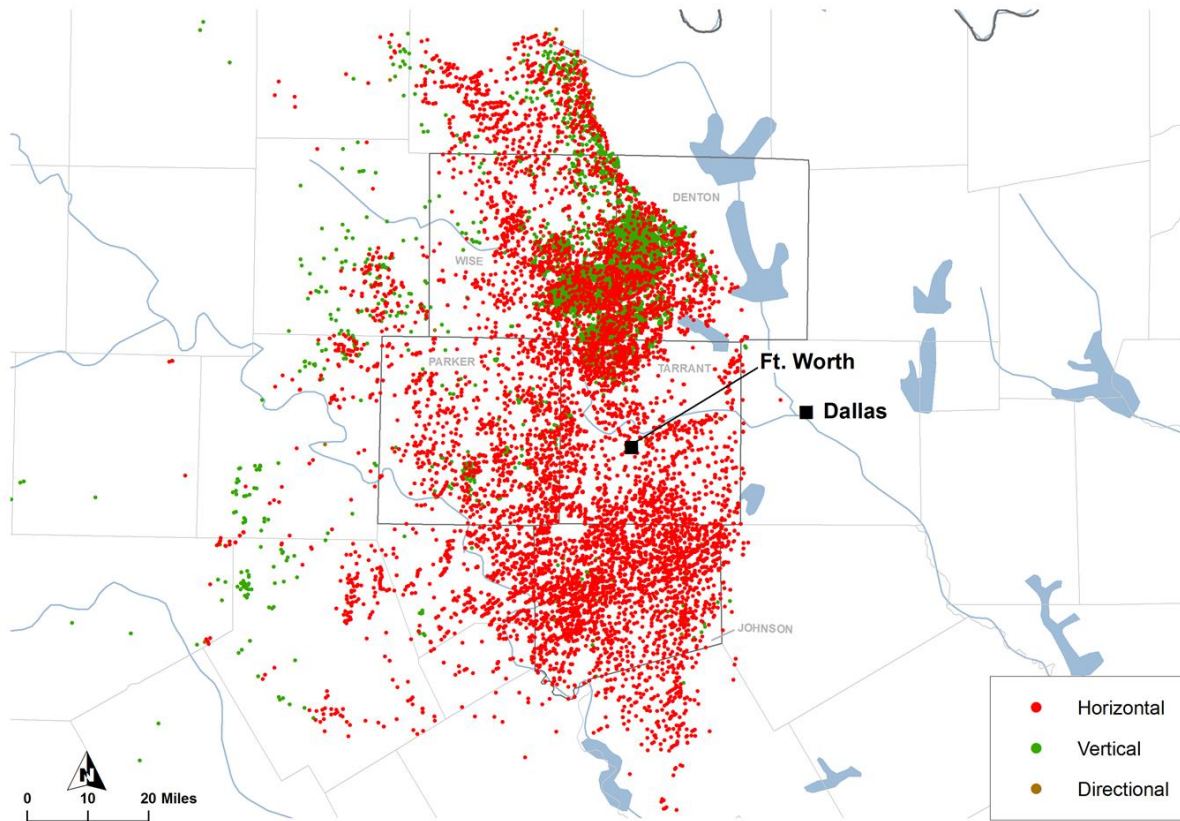


**Figure 3-8. Barnett play shale gas production and number of producing wells, 2000 to 2014.<sup>14</sup>**

Gas production data are provided on a “raw gas” basis.

<sup>14</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

Vertical wells played a significant role in the early development of the Barnett play and still produce some oil and gas, although new wells are predominantly horizontal. The evolution of the Barnett began in Denton and adjacent counties with vertical and directional wells before moving to horizontal wells as the limits of the play were defined, as illustrated in Figure 3-9.



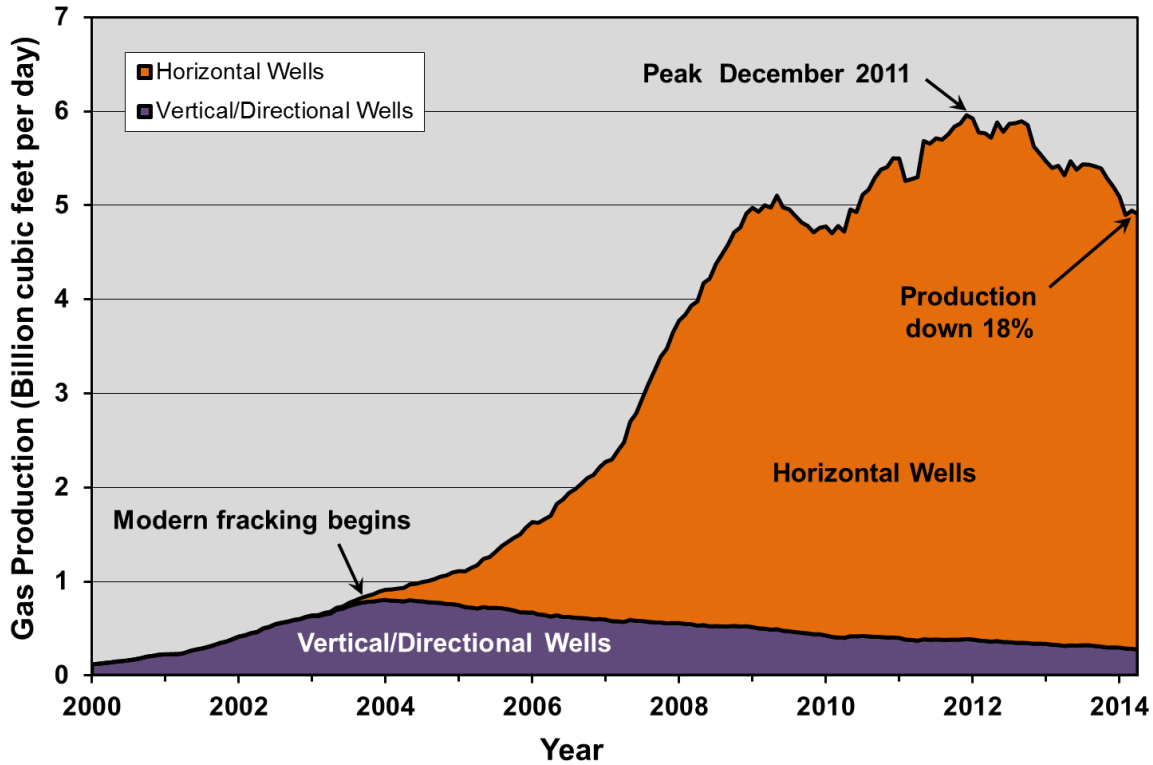
**Figure 3-9. Distribution of gas wells in Barnett play categorized by drilling type, as of early 2014.<sup>15</sup>**

Development began with vertical and directional wells in Denton County before expanding to largely horizontal drilling as the play's limits were defined.

<sup>15</sup> Data from Drillinginfo retrieved August 2014.



Production by well type is illustrated in Figure 3-10. There were still 3,366 producing vertical or directional wells, or 21% of the 15,906 producing wells in the play at the time of writing—yet these now produce less than 6% of total gas output. Very few vertical/directional wells are being drilled today; the future of the play lies in horizontal fracked wells. The dramatic growth in production from horizontal wells is noted in Figure 3-10.

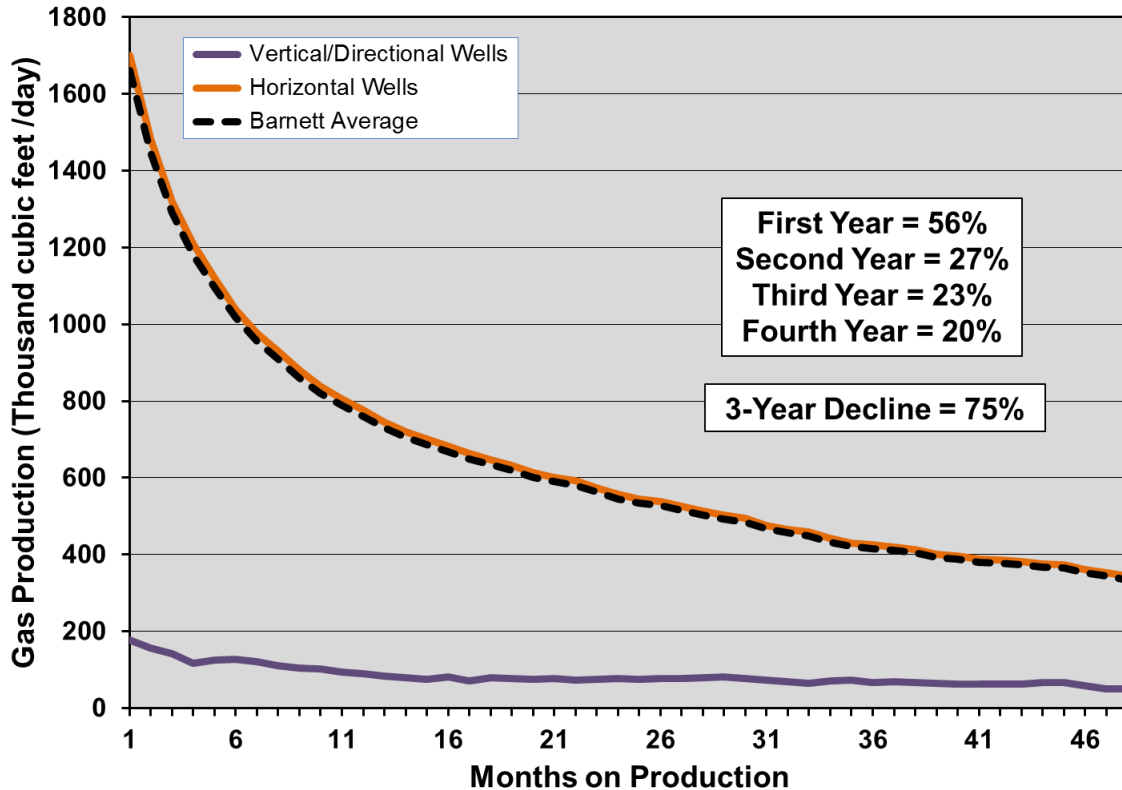


**Figure 3-10. Gas production from the Barnett play by well type, 2000 to 2014.<sup>16</sup>**  
Fracking of horizontal wells at scale got underway in the Barnett in 2003.

<sup>16</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

### 3.3.1.1 Well Decline

The first key fundamental in determining the life cycle of Barnett production is the *well decline rate*. Barnett wells exhibit high decline rates in common with all shale plays. Figure 3-11 illustrates the average decline rate of Barnett horizontal and vertical/directional wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The decline rate over the first three years of average well life is 75%, which is considerably higher than most conventional wells. As can be seen, vertical/directional wells have much lower productivity than horizontal wells and hence are being phased out.



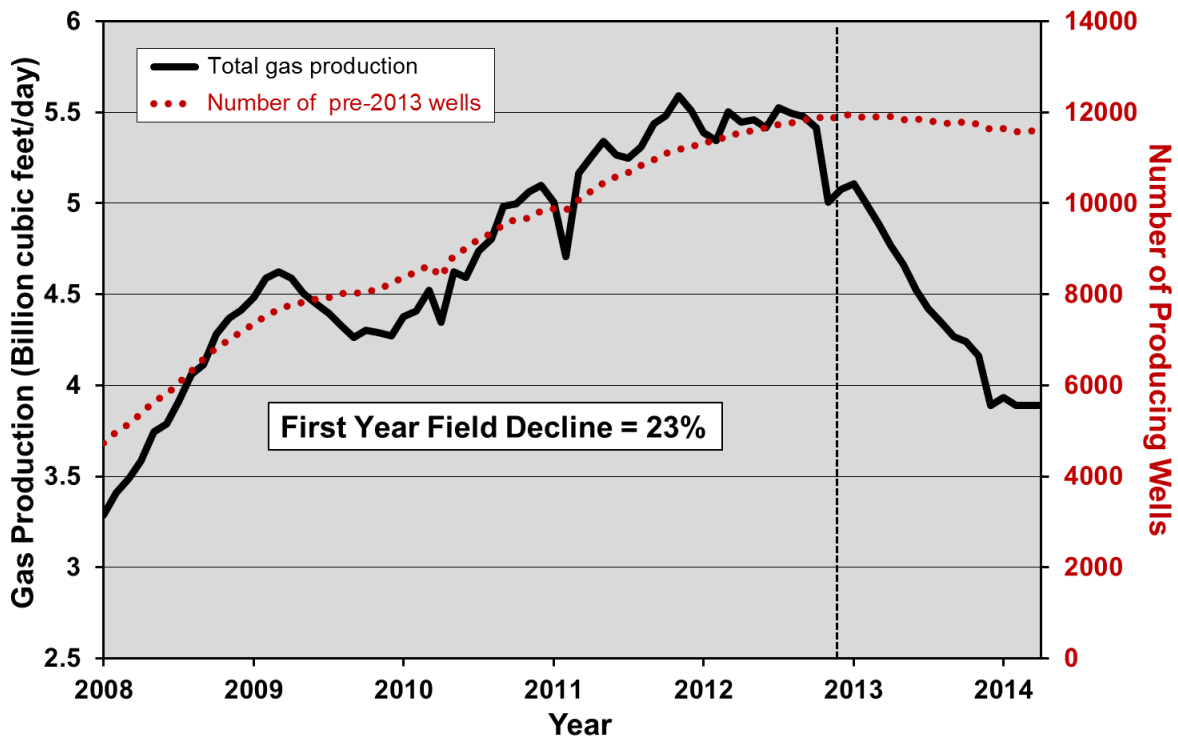
**Figure 3-11. Average decline profile for gas wells in the Barnett play.<sup>17</sup>**

Decline profile is based on all shale gas wells drilled since 2009.

<sup>17</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.1.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost for the entire play in a year without more drilling. Figure 3-12 illustrates production from the 12,000 horizontal wells drilled prior to 2013. The first-year decline rate is 23%. This is lower than the well decline rate as the field decline is made up of both new wells declining at high rates and older wells declining at lesser rates. It is also one of the lowest field decline rates observed in any shale field. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, 1,161 new wells each year would be required to offset field decline at current production levels. At an average cost of \$3.5 million per well,<sup>18</sup> this would represent a capital input of about \$4 billion per year, exclusive of leasing and other ancillary costs, just to keep production flat at 2013 levels.



**Figure 3-12. Production rate and number of horizontal shale gas wells drilled in the Barnett play prior to 2013, 2008 to 2014.<sup>19</sup>**

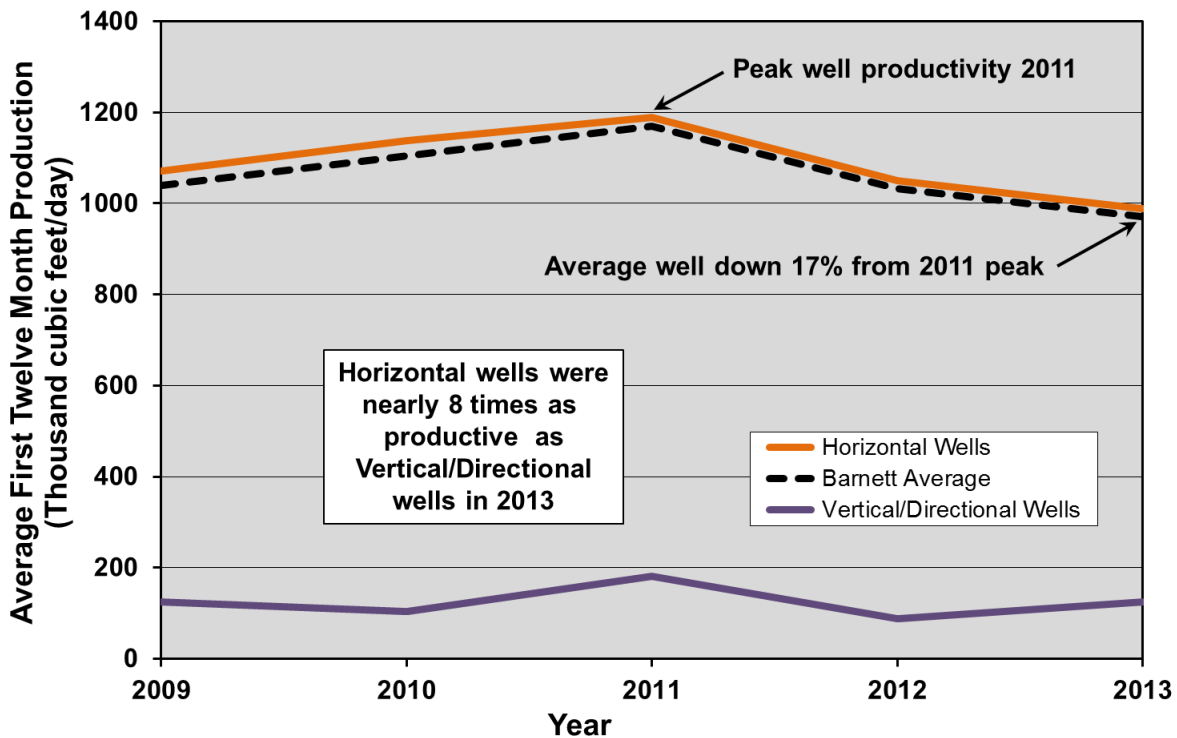
This defines the field decline for the Barnett play, which is 23% per year (only production from horizontal wells is analyzed as few vertical/directional wells are likely to be drilled in the future).

<sup>18</sup> Browning et al., 2013, Barnett Gas Production Outlook, [http://www.searchanddiscovery.com/pdfz/documents/2013/10541browning/ndx\\_browning.pdf.html](http://www.searchanddiscovery.com/pdfz/documents/2013/10541browning/ndx_browning.pdf.html).

<sup>19</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.1.3 Well Quality

The third key fundamental is the *average well quality* by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. It is, however, approaching the limits of diminishing returns, and improvements in average well quality are non-existent in the Barnett. The average first-year production rate of Barnett wells is down 17% from what it was in 2011, as illustrated in Figure 3-13. This is clear evidence that geology is winning out over technology, as drilling moves into lower-quality locations as investigated further below.

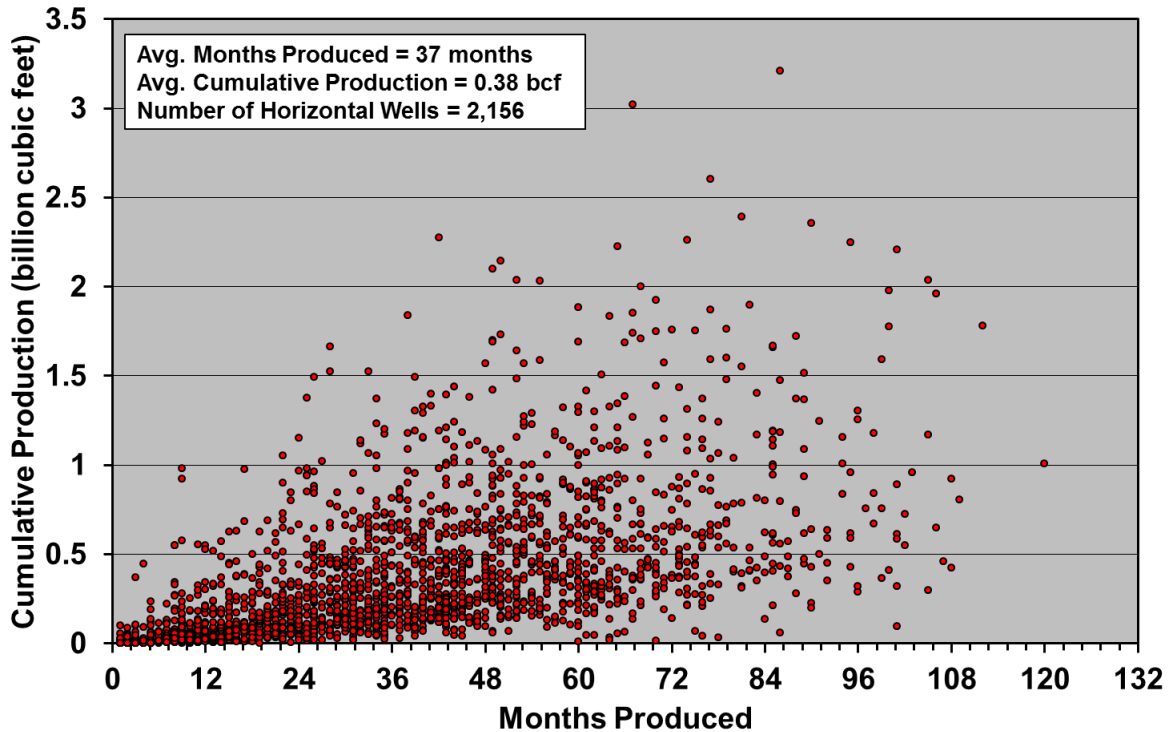


**Figure 3-13. Average first-year production rates for Barnett horizontal and vertical/directional gas wells, 2009 to 2013.<sup>20</sup>**

Average well quality has fallen by 17% from 2011, a clear indication that geology is trumping technology in this mature shale play.

<sup>20</sup> Data from Drillinginfo retrieved August 2014.

Another measure of well quality is cumulative production and well life. More than 14% of the horizontal wells that have been drilled in the Barnett are no longer productive. Figure 3-14 illustrates the cumulative production of these shut-down wells over their lifetime. At a mean lifetime of 37 months and a mean cumulative production of 0.38 billion cubic feet, these wells would in large part be economic losers.



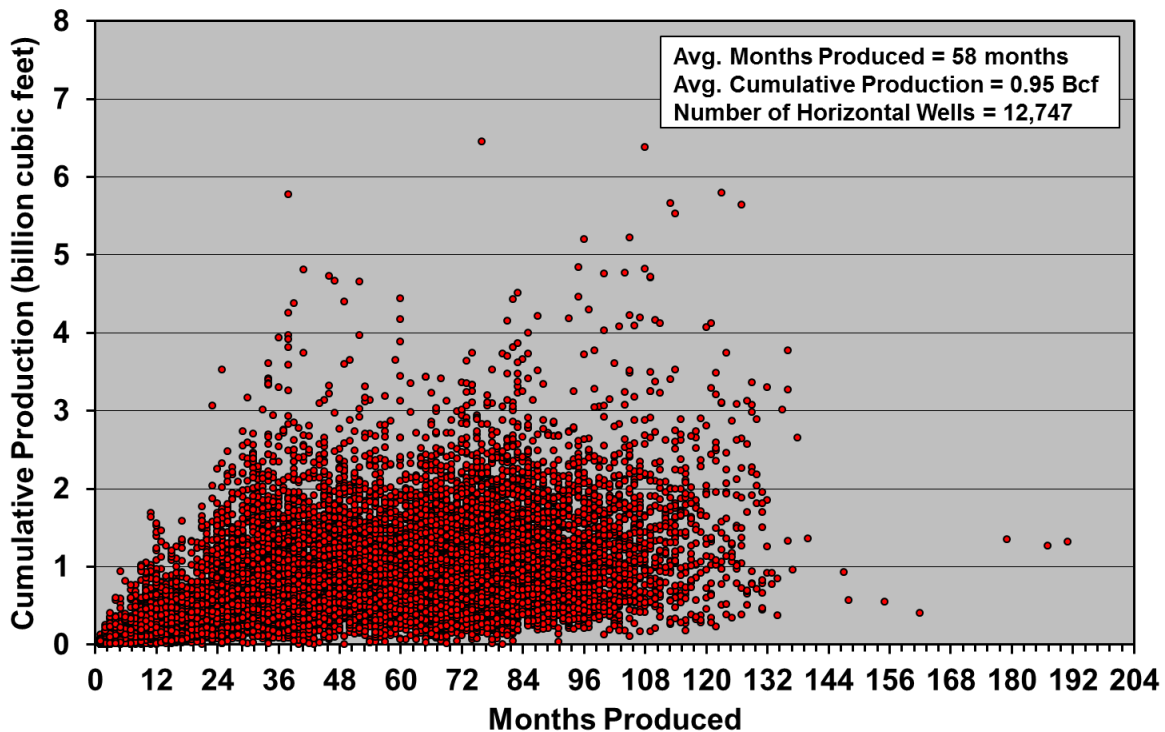
**Figure 3-14. Cumulative gas production and length of time produced for Barnett horizontal wells that were not producing as of February 2014.<sup>21</sup>**

These wells constitute more than 14% of all horizontal wells drilled; most would be economic failures, given the mean life of 37 months and average cumulative production of 0.38 billion cubic feet when production ended.

<sup>21</sup> Data from Drillinginfo retrieved August 2014.

Figure 3-15 illustrates the cumulative production of all horizontal wells that were producing in the Barnett as of March 2014. Although it can be seen that there are a few very good wells that recovered large amounts of gas in the first few years, and undoubtedly were great economic successes, the average well had produced just 0.95 billion cubic feet over a lifespan averaging 58 months. Just 1% of these wells are more than 10 years old.

The lifespan of wells is another key parameter as many operators assume a minimum well life of 30 years and longer; this is conjectural given the lack of data and the large numbers of wells that have been shut down after less than 10 years.

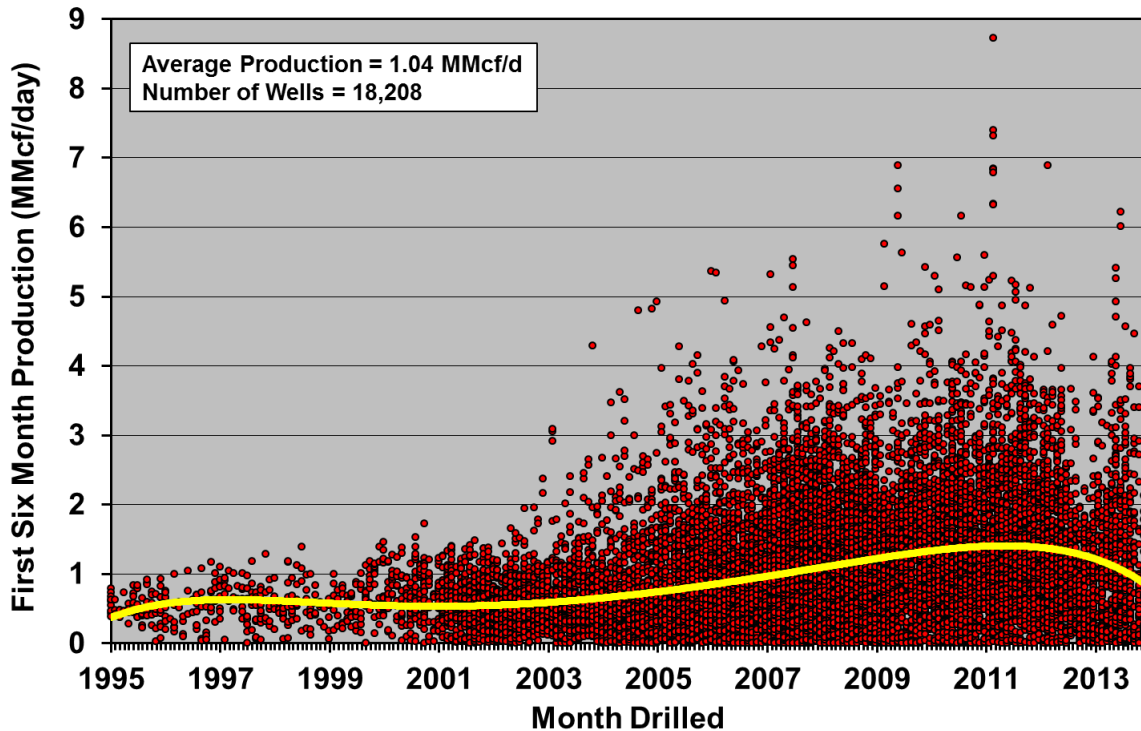


**Figure 3-15. Cumulative gas production and length of time produced for Barnett horizontal wells that were producing as of March 2014.**

These wells constitute 86% of all horizontal wells drilled. Very few wells are greater than ten years old, with a mean age of 58 months and a mean cumulative recovery of 0.95 billion cubic feet.<sup>22</sup>

<sup>22</sup> Data from Drillinginfo retrieved August 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells is not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP), which is often focused on by operators. Figure 3-16 illustrates the average daily output over the first six months of production for all wells in the Barnett play (six-month IP). Again, as with cumulative production, there are a few exceptional wells—one percent produced more than 4 million cubic feet per day (MMcf/d)—but the average for all wells drilled since 1995 is just 1.04 MMcf/d. Figure 3-7 illustrates the distribution of IPs in map form.

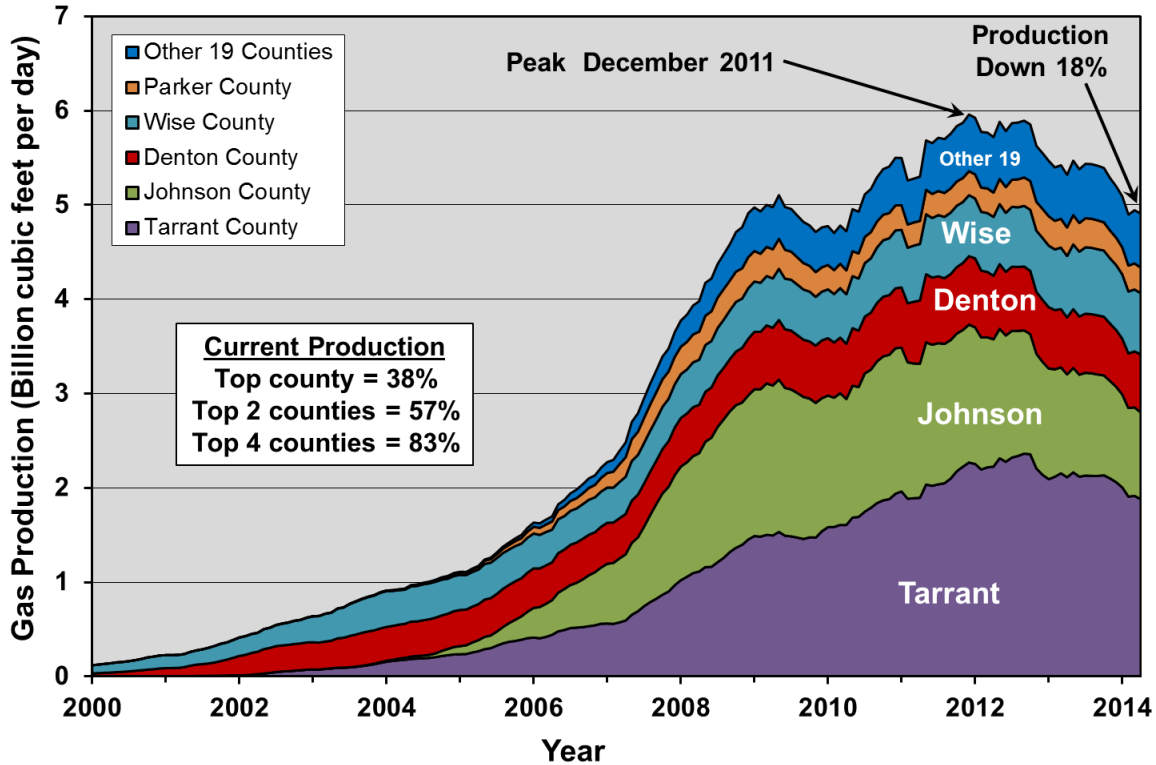


**Figure 3-16. Average gas production over the first six months for all wells drilled in the Barnett play, 1995 to 2014.**

Although there are a few exceptional wells, the average well produced 1.04 million cubic feet per day over this period.<sup>23</sup> The trend line indicates mean productivity over time.

<sup>23</sup> Data from Drillinginfo retrieved August 2014.

Different counties in the Barnett display markedly different well quality characteristics which are critical in determining the most likely production profile in the future. Figure 3-17, which illustrates production over time by county, shows that as of April 2014, the top two counties produced 57% of the total, the top five produced 88%, and the remaining 19 counties produced just 12%.

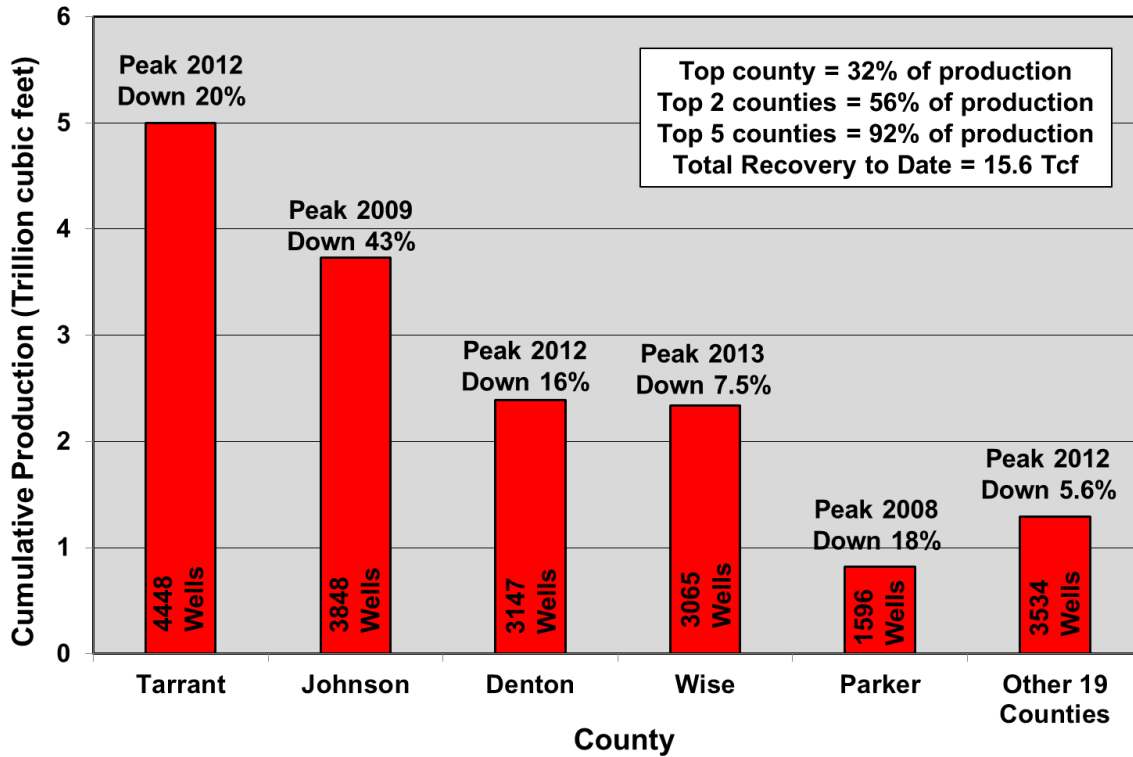


**Figure 3-17. Gas production by county in the Barnett play, 2000 through 2014.<sup>24</sup>**  
 The top five counties produced 88% of production in April 2014.

<sup>24</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.



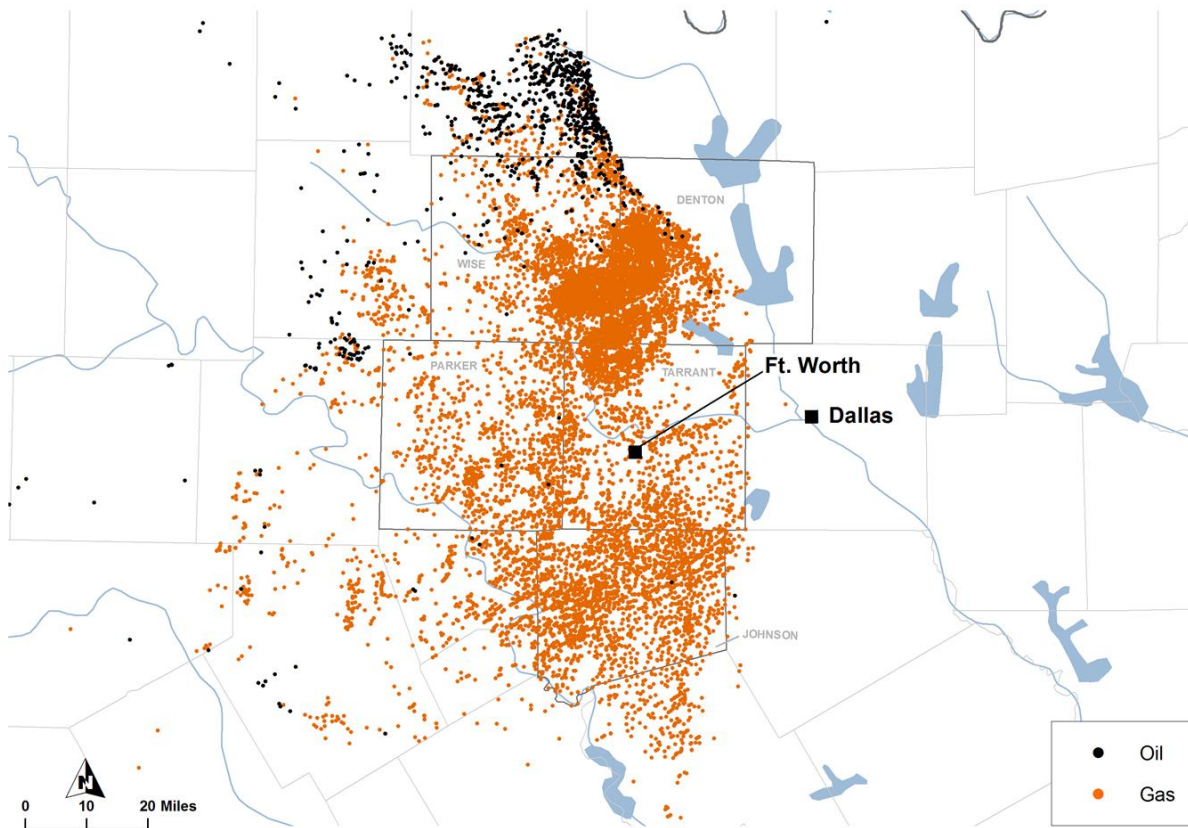
The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 3-18, the top two counties have produced 56% of the gas and the top five have produced 92%. All of the counties have peaked, although with increased drilling rates some could conceivably resume production growth.



**Figure 3-18. Cumulative gas production by county in the Barnett play through 2014.<sup>25</sup>**  
 The top five counties have produced 92% of the 15.6 trillion cubic feet of gas produced to date.

<sup>25</sup> Data from Drillinginfo retrieved August 2014.

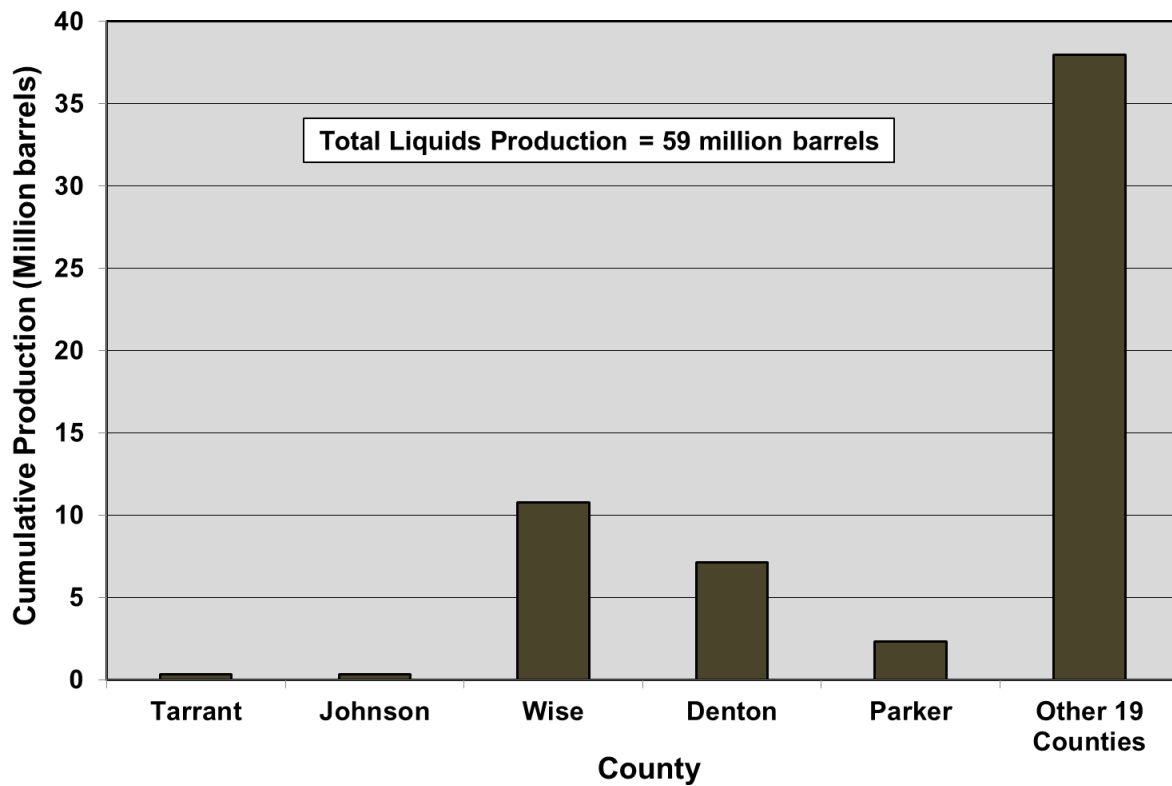
The Barnett also produces limited amounts of natural gas liquids and oil. Most liquids production is not within the top five counties but is located in the northern and western extremities of the play as illustrated in Figure 3-19. Some 59 million barrels of liquids have been produced since 2000, and although it has somewhat improved economics in marginal counties for gas production, in the big picture liquids production from the Barnett is relatively insignificant (Figure 3-20).



**Figure 3-19. Distribution of gas and oil wells in the Barnett play as of early 2014.<sup>26</sup>**

Liquids production from wells classified as “oil” occurs mainly in the northern and western extremities of the play.

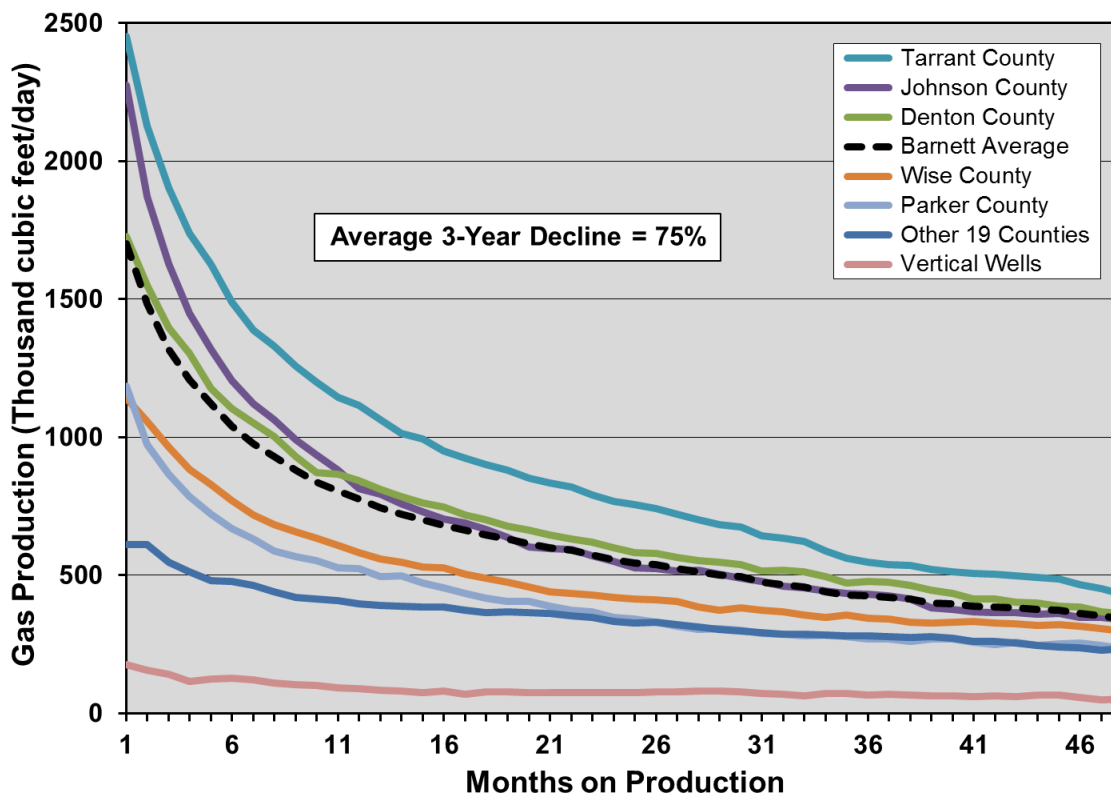
<sup>26</sup> Data from Drillinginfo retrieved August 2014.



**Figure 3-20. Cumulative liquids production by county in the Barnett play through 2014.<sup>27</sup>**  
 The “other 19” counties account for 65% of the 59 million barrels produced to date.

<sup>27</sup> Data from Drillinginfo retrieved August 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost on the order of \$3.5 million or more each in the Barnett, not including leasing costs and other expenses. The areas of highest quality—the “core” or “sweet spots”—have now been well defined. Figure 3-21 illustrates average horizontal well decline curves by county, which are a measure of well quality (recognizing that future gas production from the Barnett will be from horizontal, not vertical, wells). Initial well productivities (IPs) from Tarrant and Johnson counties are double those of Wise and Parker counties and quadruple those of the outlying 19 counties. The decline curves from the top three counties are all above the Barnett average, hence these counties are attracting the bulk of the drilling and investment—but they are nearly saturated with wells. Future drilling will have to focus more and more on lesser-quality counties.



**Figure 3-21. Average horizontal gas well decline profiles by county for the Barnett play.<sup>28</sup>**

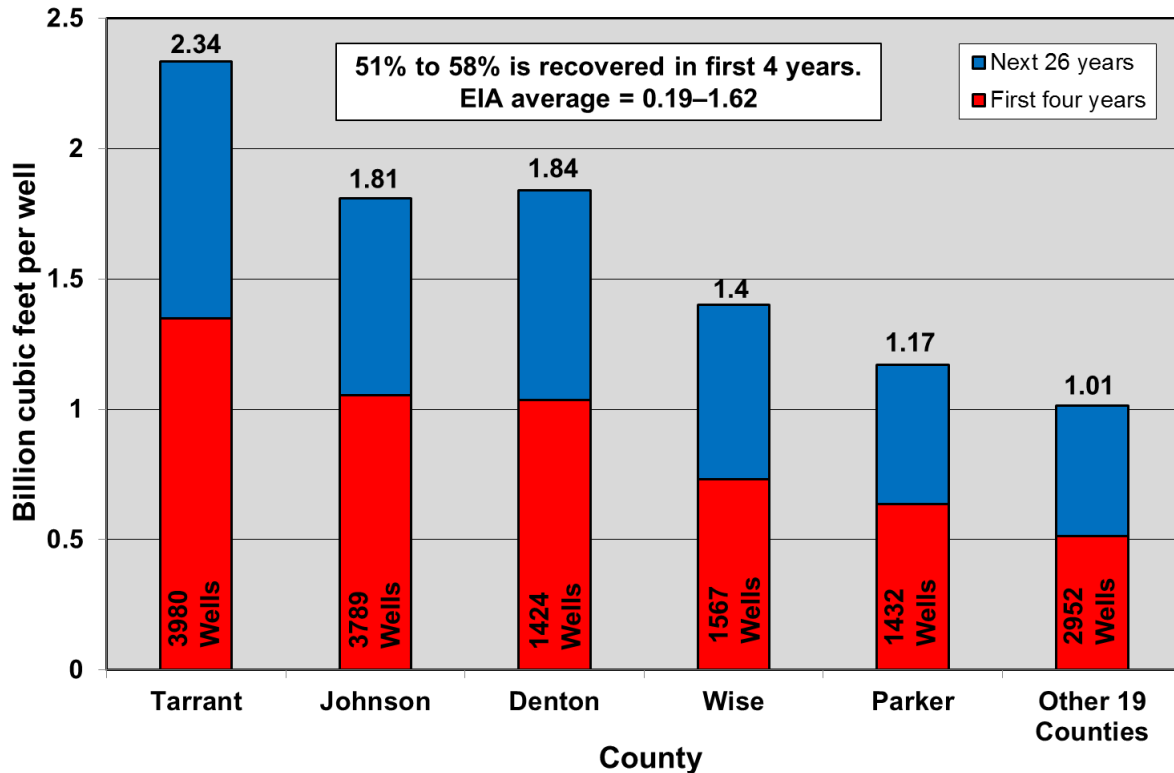
The top three counties, which have produced much of the gas in the Barnett, are clearly superior.

Another measure of well quality is “estimated ultimate recovery” or EUR—the amount of gas a well will recover over its lifetime. To be clear, no one knows what the lifespan of an average Barnett well is, given that few of them are more than ten years old (see Figure 3-14 and Figure 3-15), and some 14% of horizontal wells drilled have ceased production at an average age of just over three years. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-21, assuming well life spans of 30-50 years (as is typical for conventional wells), but so far this is speculation, given the nature of the extremely low permeability reservoirs and the completion technologies used in the Barnett. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-21, which exhibits steep initial decline with

<sup>28</sup> Data from Drillinginfo retrieved August 2014.

progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-22 illustrates theoretical EURs by county for the Barnett for comparative purposes of well quality. These range from 1.01 to 2.34 billion cubic feet per well, which are somewhat higher than the 0.19 to 1.62 billion cubic feet assumed by the EIA.<sup>29</sup> The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 51% and 58% of an average well's lifetime production occurs in the first four years.



**Figure 3-22. Estimated ultimate recovery of gas per well by county for the Barnett play.<sup>30</sup>**

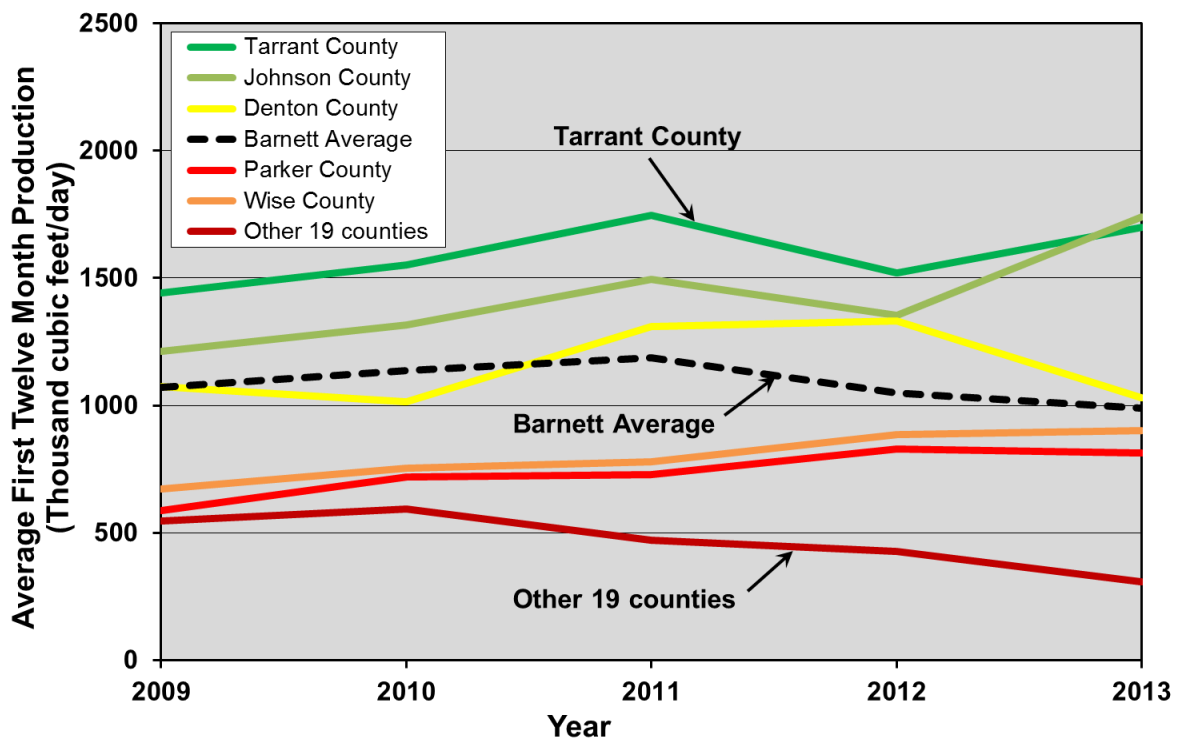
EURs are based on average well decline profiles (Figure 3-21) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life.

<sup>29</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>30</sup> Data from Drillinginfo retrieved August 2014.

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

Figure 3-23 illustrates the average first year production rate of wells by county. Notwithstanding modest recent gains in the top two counties—which are also those that are most densely drilled—the average well quality is flat or falling, as progressively more wells are drilled in lower quality parts of individual counties and in the play overall.



**Figure 3-23. Average first-year gas production rates of wells by county for the Barnett play, 2009 to 2013.<sup>31</sup>**

Well quality is rising modestly in Tarrant and Johnson counties and falling or flat in other counties. First year production rate in the lowest 19 counties, where the bulk of remaining drilling locations are, is less than a quarter of the top two counties, and is falling.

<sup>31</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.1.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled. The Bureau of Economic Geology at the University of Texas at Austin has done a detailed analysis of the Barnett in which they suggest a total of 29,217 wells will be drilled by 2030 in its base case (including 15,144 wells drilled through 2010 and 14,073 new wells to be drilled through 2030).<sup>32</sup> The range of total estimated wells in the University of Texas study was from 20,636 for its low case to 40,267 for its high case. The EIA, on the other hand, suggests that there are 6,725 square miles that can be drilled at a density of 8 wells per square mile for a total of 53,797 wells.<sup>33</sup> However, more than two-thirds of the EIA's estimated wells occur in counties with very low production potential (EUR estimated by the EIA of just 0.19 Bcf per well)—hence it is questionable if many of these wells would ever be drilled. It is also not clear if the EIA's drillable area excludes areas already drilled, which, if so, would increase the total area of the play and the number of wells that ultimately would be drilled.

A careful review of the drilling production levels by well in Figure 3-7 reveals that the limits of the Barnett play are quite well defined. Total play area is about 5,140 square miles, which translates to 41,121 locations if drilled at a density of eight wells per square mile. Given that prospective parts of Denton County now exceed eight wells per square mile (averaging 8.86 per square mile) the ultimate total well count would be 41,426 (i.e., 305 more wells than the 8 per square mile limit given the Denton County overshoot), which includes 3,732 wells drilled since 1995 that are no longer producing. This is considerably higher than the University of Texas base case estimate of wells drilled by 2030 and lower than the EIA estimate (although the Browning et al. study does not state the number of wells to be drilled beyond 2030 in any of its cases). It assumes that 21,788 wells remain to be drilled in the Barnett play, so that the well count will more than double from current levels assuming that capital input is not a constraint in drilling marginal wells. It also assumes that drilling will not be constrained by surface features such as towns, parks etc. and thus is a best case estimate.

Table 3-1 lists the critical parameters used for determining the future production rates of the Barnett play.

<sup>32</sup> Browning et al., 2014, *Oil and Gas Journal*, "BARNETT SHALE MODEL-2 (Conclusion): Barnett study determines full-field reserves, production forecast," <http://www.ogj.com/articles/print/volume-111/issue-9/drilling-production/barnett-study-determines-full-field-reserves.html>.

<sup>33</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

Parameter	County						Total
	Denton	Johnson	Parker	Tarrant	Wise	Other 19	
Production April 2014 (Bcf/d)	0.61	0.92	0.27	1.88	0.65	0.57	4.91
% of Field Production	13	19	6	38	13	12	100
Cumulative Gas (Tcf)	2.39	3.73	0.82	5	2.34	1.29	15.57
Cumulative Liquids (MMBBL)	7.14	0.32	2.31	0.31	10.76	37.99	58.85
Number of Wells	3147	3848	1596	4448	3065	3534	19638
Number of Producing Wells	2678	3028	1135	3735	2608	2722	15906
Average EUR per well (Bcf)	1.84	1.81	1.17	2.34	1.4	1.01	1.70
Field Decline (%)	19.05	23.81	25.75	24.86	22.56	20.58	23.37
3-Year Well Decline (%)	72	81	77	78	70	55	75
Peak Year	Jan-12	May-09	Dec-08	Sep-12	Oct-13	May-12	Dec-11
% Below Peak	16	43	18	20	7.5	5.6	18
Average First Year Production in 2013 (Mcf/d)	1032	1740	812	1701	900	308	988
New Wells Needed to Offset Field Decline	113	126	86	275	163	382	1161
Area in square miles	888	729	904	864	905	19000	23290
% Prospective	40	90	90	80	80	10	22
Net Square Miles	355.2	656.1	813.6	691.2	724	1900	5140
Well Density per square mile	8.86	5.86	1.96	6.44	4.23	1.86	3.82
Additional locations to 8/sq. Mile	0	1401	4913	1082	2727	11666	21788
Population	584238	126811	88495	1446219	48793	N/A	N/A
Total Wells 8/sq. Mile	3147	5249	6509	5530	5792	15200	41426
Total Producing Wells 8/sq. Mile	2678	4429	6048	4817	5335	14388	37694

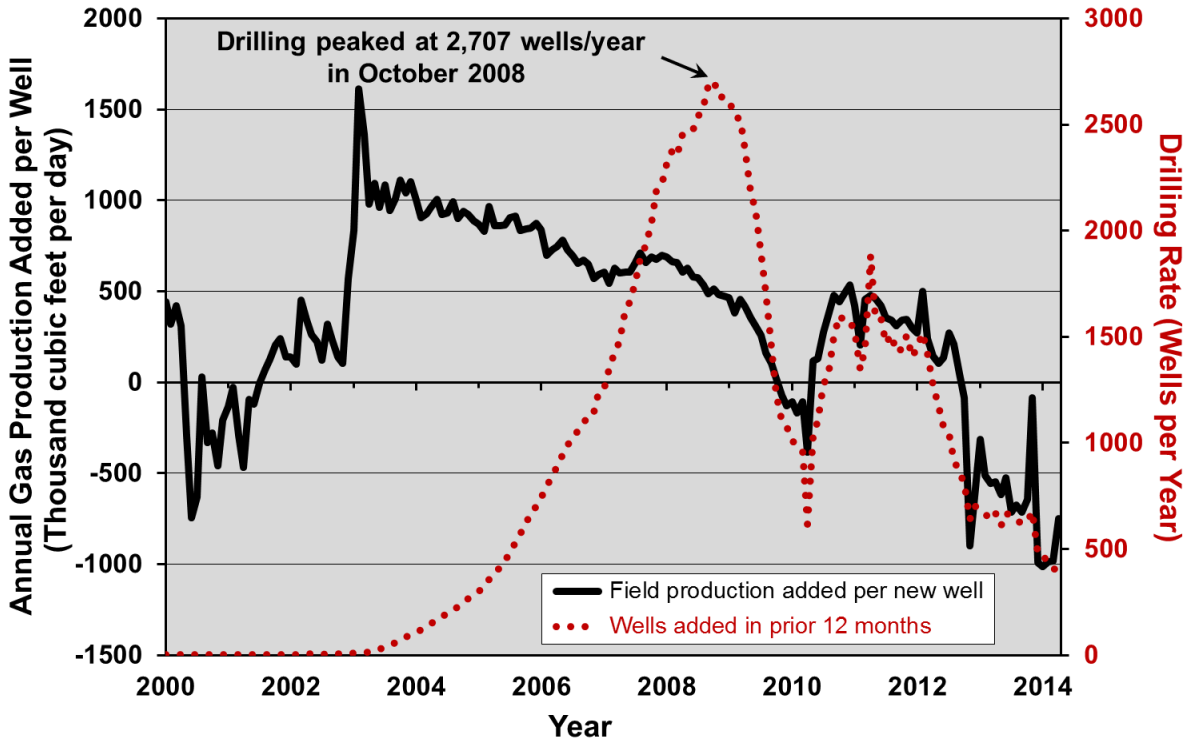
**Table 3-1. Parameters for projecting Barnett production, by county.**

Area in square miles under "Other" is estimated.



### 3.3.1.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling—the fifth key fundamental. Figure 3-24 illustrates the historical drilling rates in the Barnett. Horizontal drilling rates peaked in 2008 at 2,707 wells per year and have fallen to current levels of less than 400 wells per year. Current drilling rates are far less than the 1,161 wells per year required to maintain production at current levels, hence each new well drilled now serves only to slow the overall production decline of the play.



**Figure 3-24. Annual gas production added per new horizontal well and annual drilling rate in the Barnett play, 2000 through 2014.<sup>34</sup>**

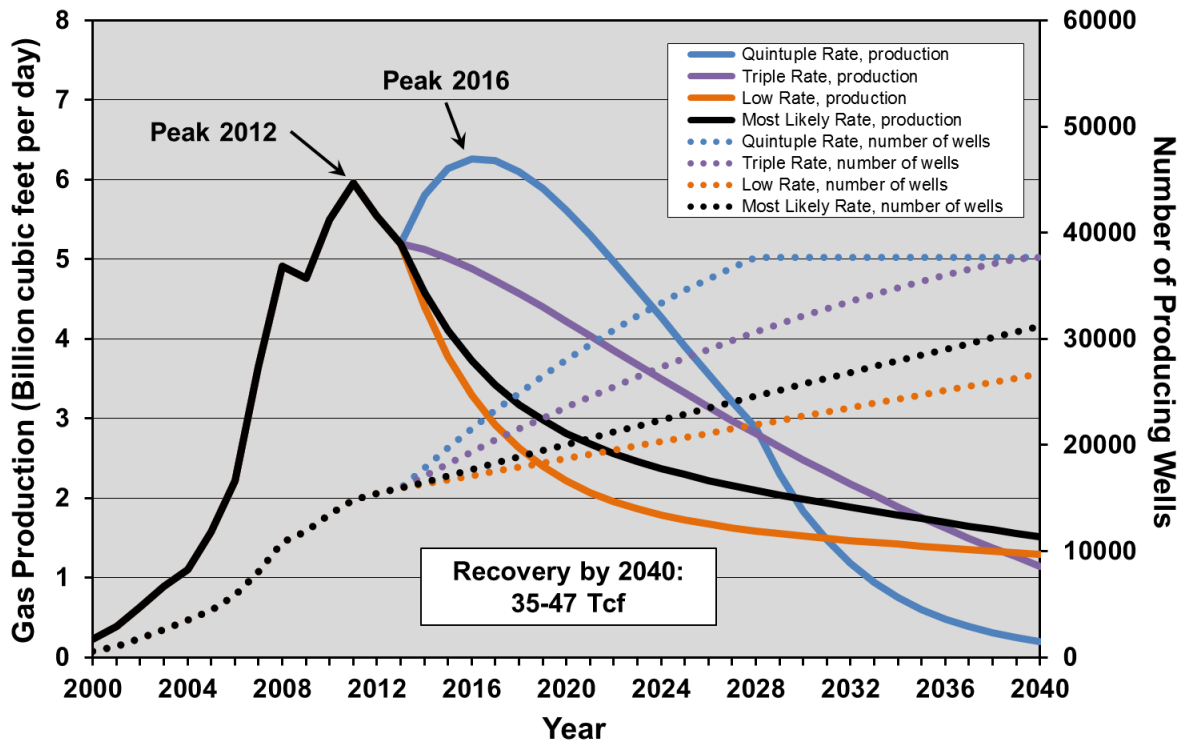
Drilling rate peaked in 2008 and is now far below the level needed to keep production flat, hence each new well now only serves to slow the overall production decline of the play.

<sup>34</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

### 3.3.1.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Barnett play were developed to illustrate the effects of changing the rate of drilling. Figure 3-25 illustrates the production profiles of four drilling rate scenarios if 100% of the prospective play area is drillable at eight wells per square mile. These scenarios are:

1. MOST LIKELY RATE scenario: Drilling increases from the current rate to 600 wells per year, then gradually declines to 500 wells per year
2. LOW RATE scenario: Drilling continues at current level of 400 wells per year, holding constant.
3. TRIPLE RATE scenario: Drilling increases to 1,200 wells per year, then gradually declines to 600 wells per year.
4. QUINTUPLE RATE scenario: Drilling increases to 2,000 per year, then gradually declines to 1,000 wells per year.



**Figure 3-25. Four drilling rate scenarios of Barnett gas production (assuming 100% of the area is drillable at eight wells per square mile).<sup>35</sup>**

“Most Likely Rate” scenario: drilling increases to 600 wells/year, declining to 500 wells/year.  
 “Low Rate” scenario: drilling continues at 400 wells/year, holding constant.  
 “Triple Rate” scenario: drilling increases to 1,200 wells/year, declining to 600 wells/year.  
 “Quintuple Rate” scenario: drilling increases to 2,000 wells/year, declining to 1,000 wells/year.  
 Although the peak month was December 2011, on a total year production basis the peak year is 2012.

<sup>35</sup> Data from Drillinginfo retrieved August 2014.

The drilling rate scenarios have the following results:

1. MOST LIKELY RATE scenario: The drilling rate declines after its initial increase as drilling moves into poorer quality locations. Total gas recovery by 2040 would be 39.2 trillion cubic feet, and drilling would continue beyond 2040.
2. LOW RATE scenario: Total gas recovery by 2040 would be 34.8 trillion cubic feet, and drilling would continue beyond 2040.
3. TRIPLE RATE scenario: Total gas recovery by 2040 would be 45.6 trillion cubic feet, and drilling would end by 2039.
4. QUINTUPLE RATE scenario: The current production decline would be reversed and grow to a new peak in 2016; however, drilling locations would run out by 2028 followed by a steep production decline, making the supply situation much worse in later years than in the “Most Likely Rate” scenario. Total gas recovery by 2040 would be 46.7 trillion cubic feet.

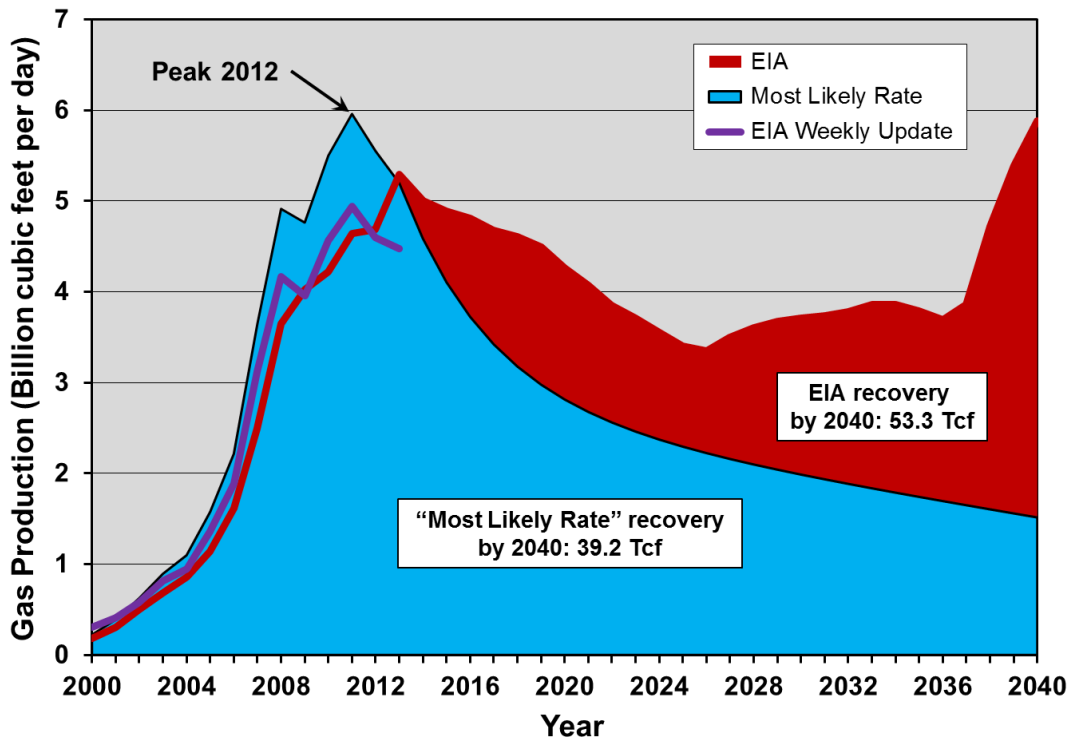
Both the recovery of 39.2 trillion cubic feet by 2040 in the “Most Likely Rate” scenario and the recovery of 46.7 trillion cubic feet in the “Quintuple Rate” scenario agree well with the University of Texas study, which calculates an ultimate recovery of 45 Tcf for the Barnett.<sup>36</sup> (They continue their analysis through 2050 for their ultimate recovery estimate, hence there is almost perfect agreement with the “Most Likely Rate” scenario given that considerably more gas would be recovered after 2040).

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<sup>36</sup> Browning et al., 2014, *Oil and Gas Journal*, “BARNETT SHALE MODEL-2 (Conclusion): Barnett study determines full-field reserves, production forecast,” <http://www.ogj.com/articles/print/volume-111/issue-9/drilling-production/barnett-study-determines-full-field-reserves.html>.

### 3.3.1.7 Comparison to EIA Forecast

Figure 3-26 illustrates the EIA's projection for Barnett production through 2040 compared to the "Most Likely Rate" scenario. The EIA projects a recovery by 2040 of 53.3 Tcf to meet its reference case forecast (44.4 Tcf between 2012 and 2040). Not only is this far higher than the projections of this report and the University of Texas study, it *projects a new high in production in 2040*, which implies very considerable future production after 2040. Furthermore, this amounts to *the complete recovery of all of the EIA's estimated 20.3 Tcf of proved reserves by 2040*<sup>37</sup> plus 23.7 Tcf of unproved resources (44 Tcf in total).<sup>38</sup> This strains credibility to the limit; how can all the proved and unproved resources and reserves be extracted and still have production at all-time highs in 2040?



**Figure 3-26. "Most Likely Rate" scenario of Barnett gas production compared to the EIA reference case, 2000 to 2040.<sup>39</sup>**

The EIA assumes the Barnett will reach a new all-time high by 2040 after producing all proved reserves and unproved resources, and presumably produce a great deal more gas in the post-2040 period. Note that although the peak month was December 2011, on a total year production basis the peak year is 2012. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis. The EIA production data are also shown on a dry basis; the difference between the EIA's data and the Drillinginfo data used in this report may be due to the shrinkage factor between "raw" and "dry" gas.<sup>40</sup>

<sup>37</sup> EIA, 2014, Principal shale gas plays: natural gas production and proved reserves, 2011-12, [http://www.eia.gov/naturalgas/crudeoilreserves/excel/table\\_4.xls](http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls).

<sup>38</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>39</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>40</sup> EIA, *Natural Gas Weekly Update*, retrieved October 2014, <http://www.eia.gov/naturalgas/weekly>

### 3.3.1.8 Barnett Play Analysis Summary

Several things are clear from this analysis:

1. Drilling rates have fallen markedly in the Barnett due to gas prices and to saturation of sweet spots with wells.
2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Current drilling rates of 384 wells per year are far below the level of 1,161 wells per year required to maintain production, which would require the investment of \$4 billion per year for drilling (assuming \$3.5 million per well). Future production profiles are most dependent on drilling rate and, to a lesser extent, on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Maintaining or growing production in the Barnett would require much higher gas prices to justify higher drilling rates.
3. Quintupling current drilling rates could reverse the current production decline and raise production to a new peak in the 2016 timeframe, but would increase cumulative recovery only by 19% by 2040 and wouldn't change the ultimate recovery of the play. Increasing drilling rates effectively recovers the gas sooner, making the supply situation worse later.
4. The projected recovery of 39.2 Tcf by 2040 in this report's "Most Likely Rate" scenario is comparable to the University of Texas study's ultimate recovery of 45 Tcf (given that considerable gas would be recovered in the "Most Likely Rate" scenario after 2040).<sup>41</sup> Both are significantly less than the EIA's reference case projection of 53.3 Tcf by 2040.
5. This report's projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained. They also assume that 100% of the prospective area is drillable. This is not a sure thing as drilling in the poorer quality parts of the play will require much higher gas prices to be economic. Failure to maintain drilling rates will result in a steeper drop off in production.
6. More than double the current number of producing wells will need to be drilled to meet the production projection of the "Most Likely Rate" scenario over the next several decades.
7. The EIA projection for future Barnett gas production included in its reference case forecast for AEO 2014<sup>42</sup> strains credibility to the limit. It is highly unlikely to be realized, especially at the gas prices the EIA forecasts.<sup>43</sup>

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<sup>41</sup> Browning et al., 2014, *Oil and Gas Journal*, "BARNETT SHALE MODEL-2 (Conclusion): Barnett study determines full-field reserves, production forecast," <http://www.ogj.com/articles/print/volume-111/issue-9/drilling-production/barnett-study-determines-full-field-reserves.html>.

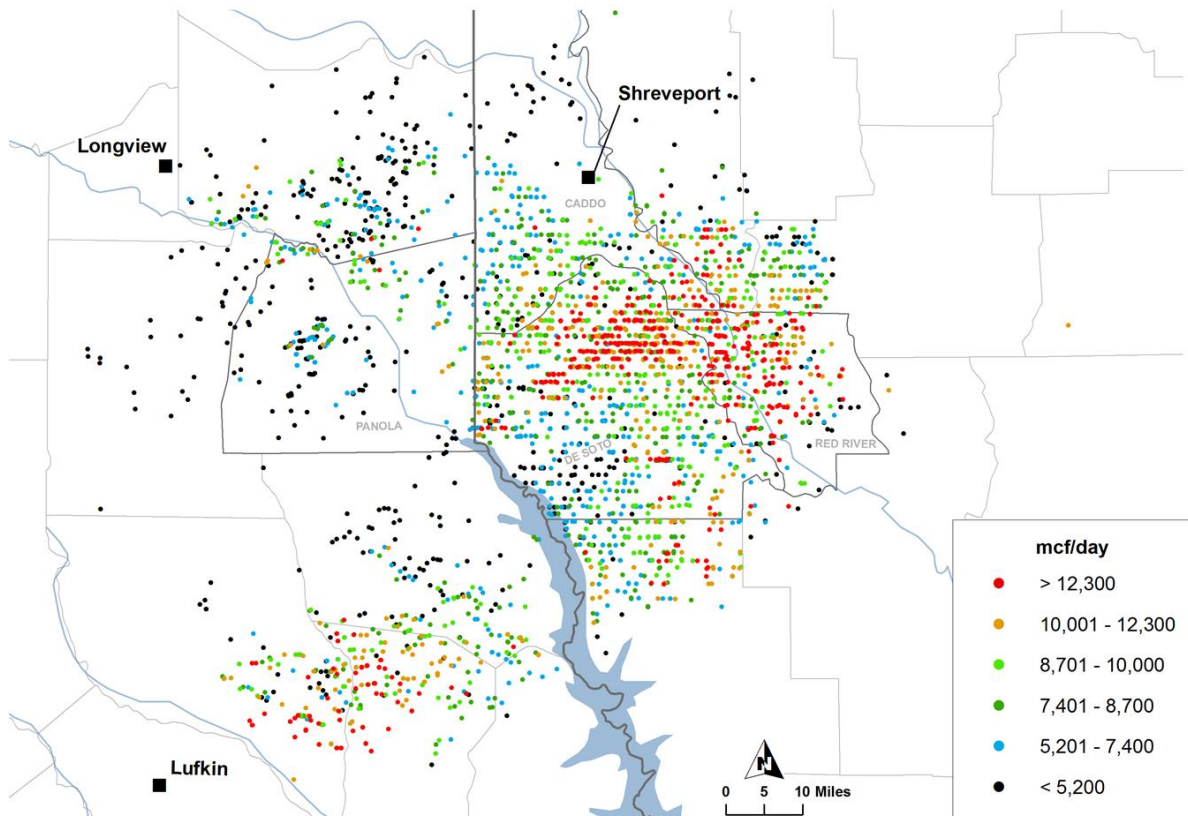
<sup>42</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>43</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/>.

### 3.3.2 Haynesville Play

The EIA forecasts recovery of 102 Tcf of gas from the Haynesville play by 2040. The analysis of actual production data presented below suggests that this forecast is highly unlikely to be realized.

The Haynesville play was discovered in 2007 and production rapidly increased until it became the largest shale gas play in the U.S. at its peak in early 2012. Figure 3-27 illustrates the distribution of wells as of early 2014. Over 3,500 wells have been drilled to date, of which 3,274 were producing at the time of writing. The play covers parts of 16 counties although most of the drilling is concentrated in Caddo, DeSoto, and Red River parishes in Louisiana and Panola County in east Texas. The map shows a high density of wells in the central and eastern parts of the play area, with a significant concentration of high-producing wells (red and orange) in the Caddo and DeSoto parishes.

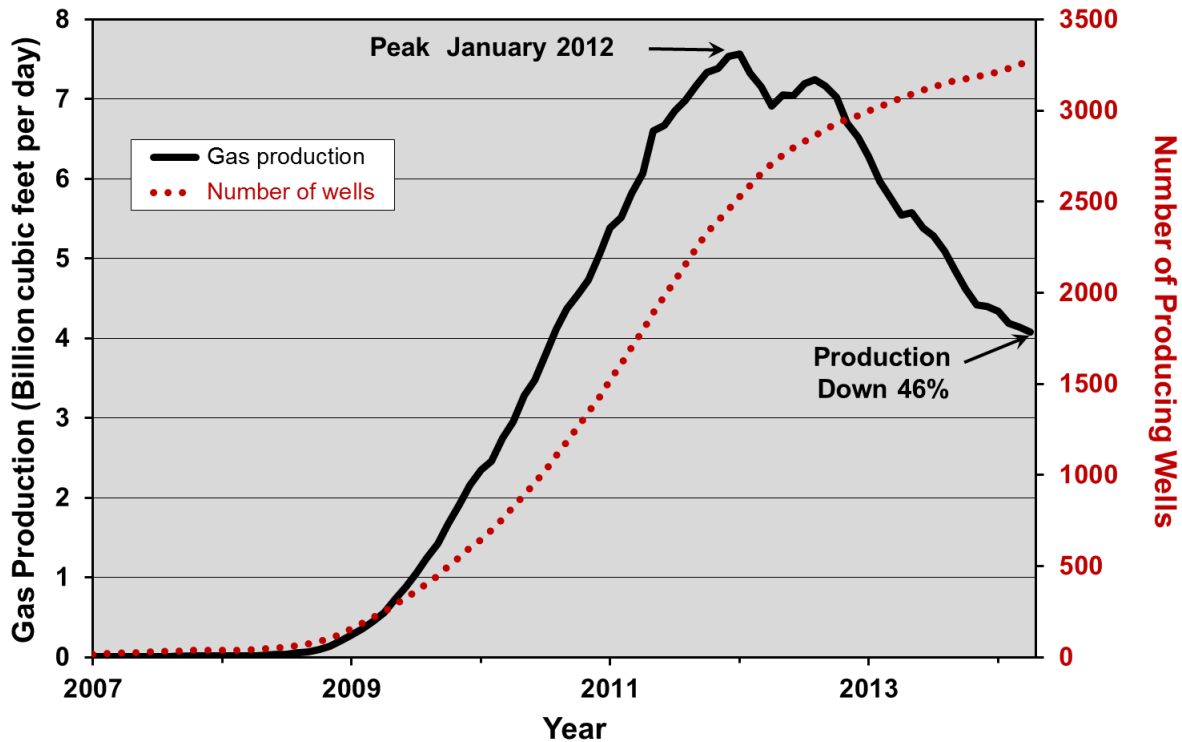


**Figure 3-27. Distribution of wells in the Haynesville play as of early 2014, illustrating highest one-month gas production (initial productivity, IP).<sup>44</sup>**

Well IPs are categorized approximately by percentile; see Appendix.

<sup>44</sup> Data from Drillinginfo retrieved April 2014.

Production in the Haynesville peaked at more than 7 billion cubic feet per day in January 2012 as illustrated in Figure 3-28. Ninety-five percent of current production is from horizontal fracked wells. Horizontal drilling grew from virtually nothing in 2008 to a peak rate of 1,050 wells per year in mid-2011. It has since fallen to 215 wells per year, which is insufficient to offset field decline. Drilling rates required to keep production flat at current production levels are about 400 wells per year.



**Figure 3-28. Haynesville play shale gas production and number of producing wells, 2007 to 2014.<sup>45</sup>**

Gas production data are provided on a “raw gas” basis.

<sup>45</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

Although vertical and directional wells played a role in the early development of the Haynesville play and still produce some oil and gas, new wells are predominantly horizontal. There are still 417 producing vertical and directional wells at the time of writing, or 14% of the 3,274 producing wells in the play, yet they produce less than 5% of gas output. Production by well type is illustrated in Figure 3-29. Very few vertical/directional wells are being drilled today—the future of the play lies in horizontal fracked wells.

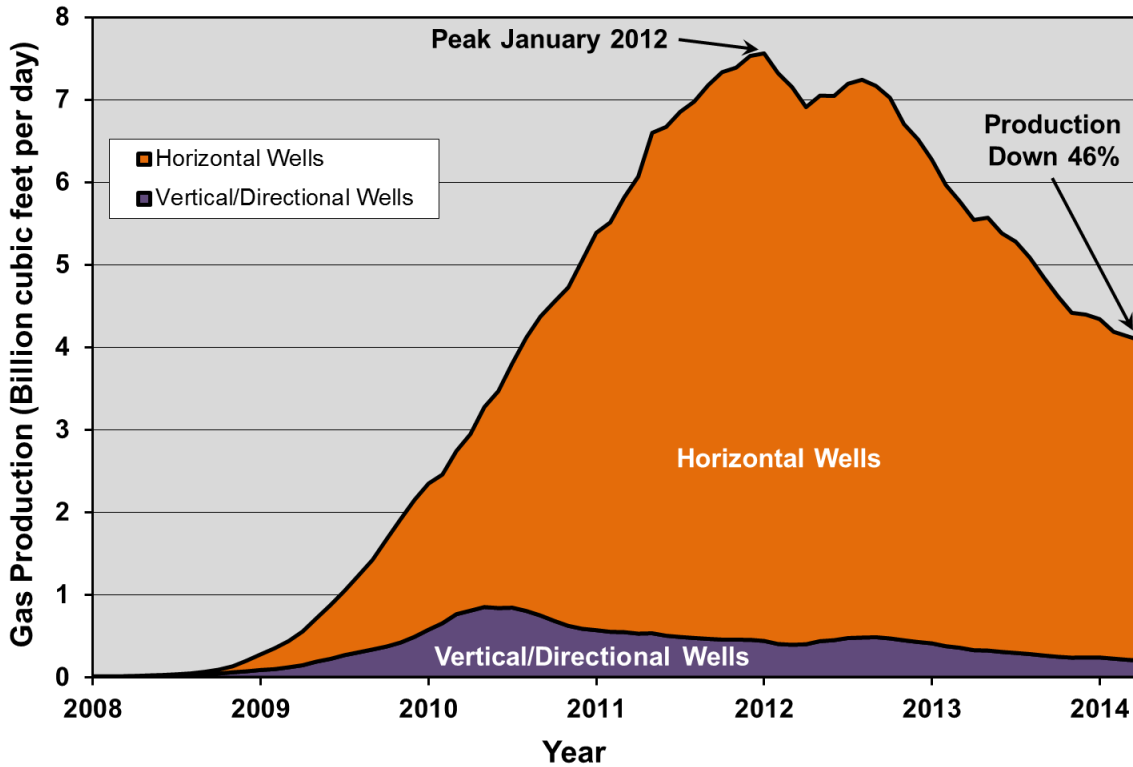


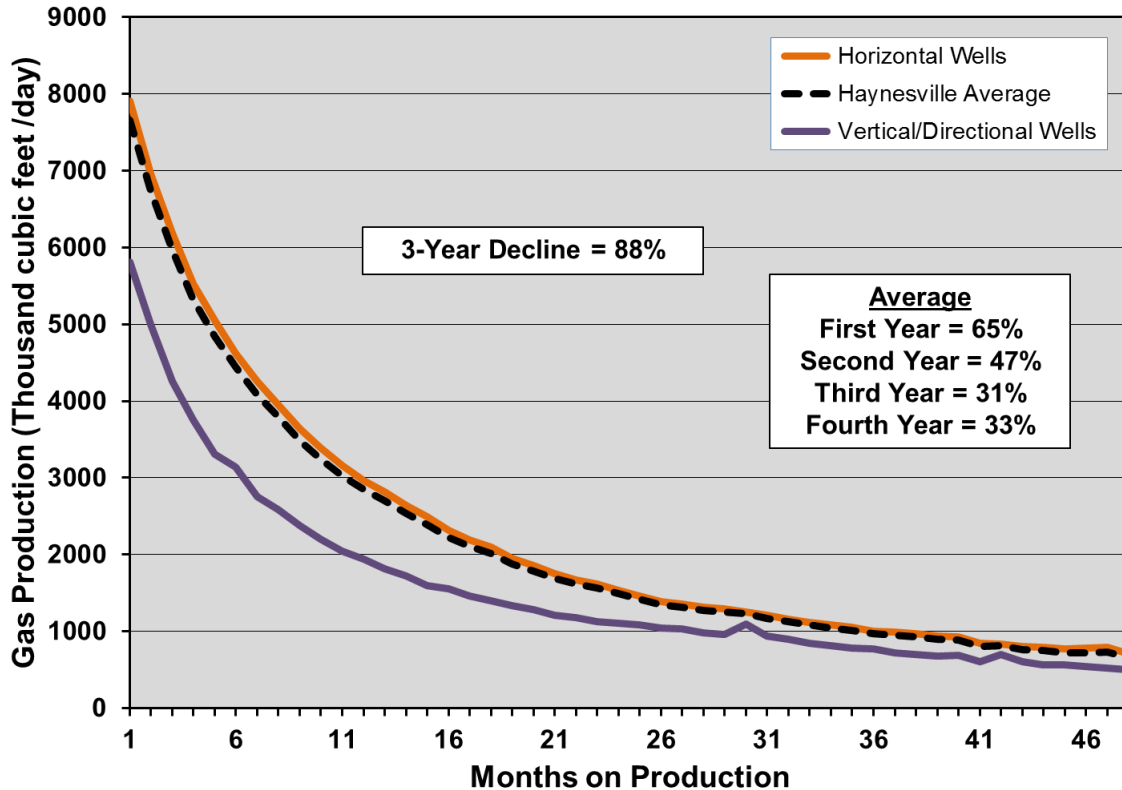
Figure 3-29. Gas production from the Haynesville play by well type, 2008 to 2014.<sup>46</sup>

<sup>46</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.



### 3.3.2.1 Well Decline

The first key fundamental in determining the life cycle of Haynesville production is the *well decline rate*. Haynesville wells exhibit high decline rates in common with all shale plays. Figure 3-30 illustrates the average decline rate of the most recent Haynesville horizontal and vertical/directional wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The average decline rate over the first three years of well life is 88%, one of the highest of the plays analyzed. As can be seen, vertical/directional wells have lower productivity than horizontal wells and hence are being phased out.



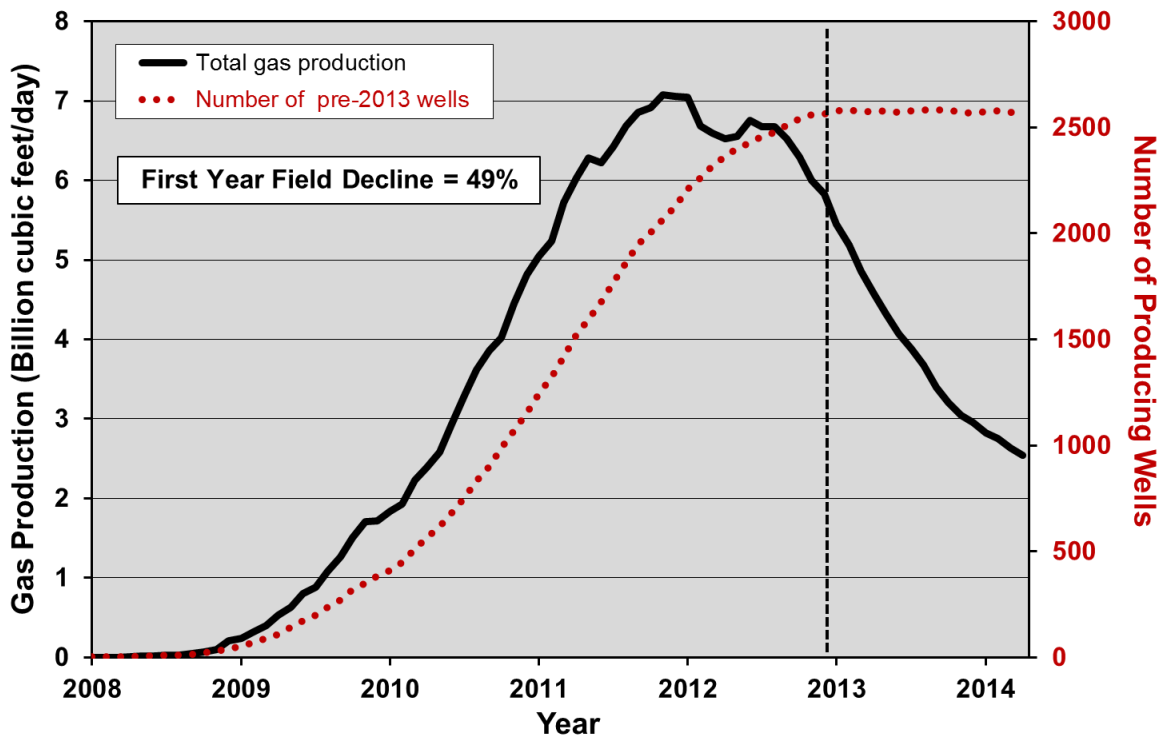
**Figure 3-30. Average decline profile for gas wells in the Haynesville play.<sup>47</sup>**

Decline profile is based on all shale gas wells drilled since 2009.

<sup>47</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.2.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost in a year in the Haynesville without more drilling. Figure 3-31 illustrates production from the 2,600 horizontal wells drilled prior to 2013. The first-year decline is 49%. This is lower than the well decline rate as the field decline is made up of both new wells declining at high rates and older wells declining at lesser rates. It is also one of the highest field decline rates observed in any shale field. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, approximately 400 new wells each year would be required to offset field decline at current production levels. At an average cost of \$9 million per well<sup>48</sup>, this would represent a capital input of about \$3.6 billion per year, exclusive of leasing and other ancillary costs, just to keep production flat at 2014 levels.



**Figure 3-31. Production rate and number of horizontal shale gas wells drilled in the Haynesville play prior to 2013, 2008 to 2014.<sup>49</sup>**

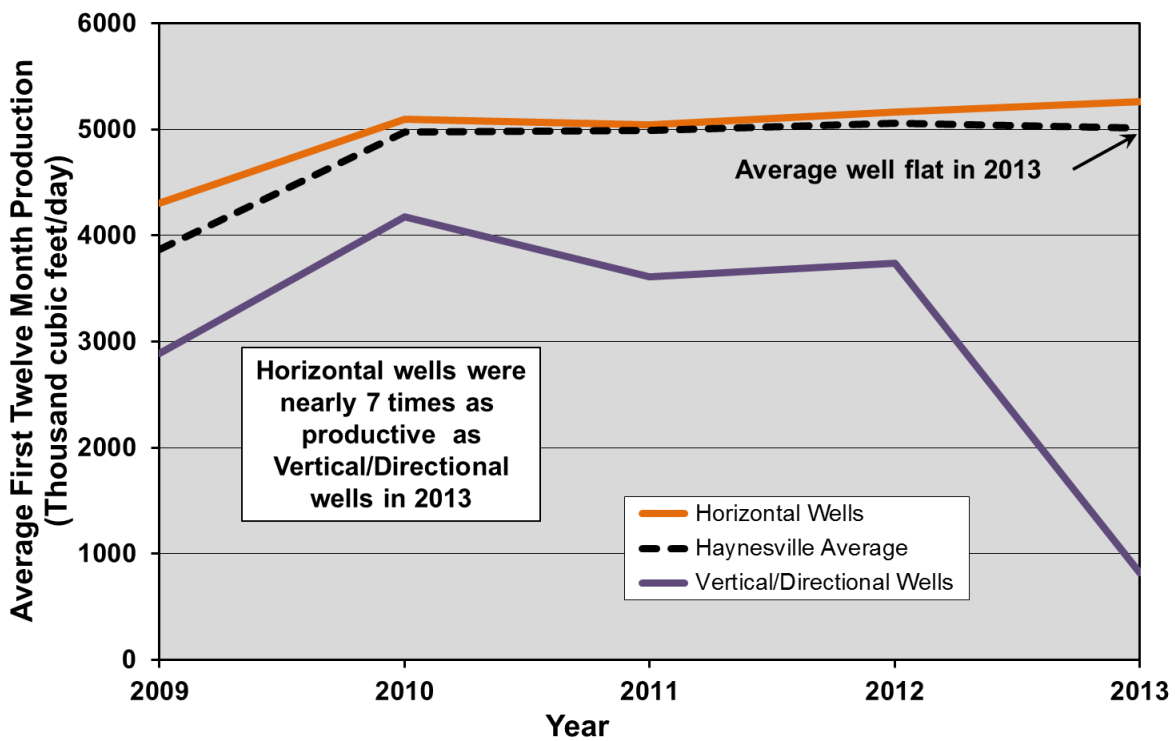
This defines the field decline for the Haynesville play, which is 49% per year (only production from horizontal wells is analyzed as few vertical/directional wells are likely to be drilled in the future).

<sup>48</sup> Mark J. Kaiser, June 2014, *Oil and Gas Journal*, "HAYNESVILLE UPDATE—2: North Louisiana drilling costs vary slightly 2007-12," <http://www.ogj.com/articles/print/volume-112/issue-1/exploration-development/north-louisiana-drilling-costs-vary-slightly-2007-12.html>.

<sup>49</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.2.3 Well Quality

The third key fundamental is the *average well quality* by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. It is, however, approaching the limits of diminishing returns, and improvements in average well quality appear to have ended in the Haynesville. The average first-year production rate of Haynesville wells has been flat over the past year after rising significantly in the early years of the play, as illustrated in Figure 3-32. This is clear evidence that geology is winning out over technology, as drilling moves into lower-quality locations (as investigated further below), given that operators tend to apply more sophisticated technology over time.

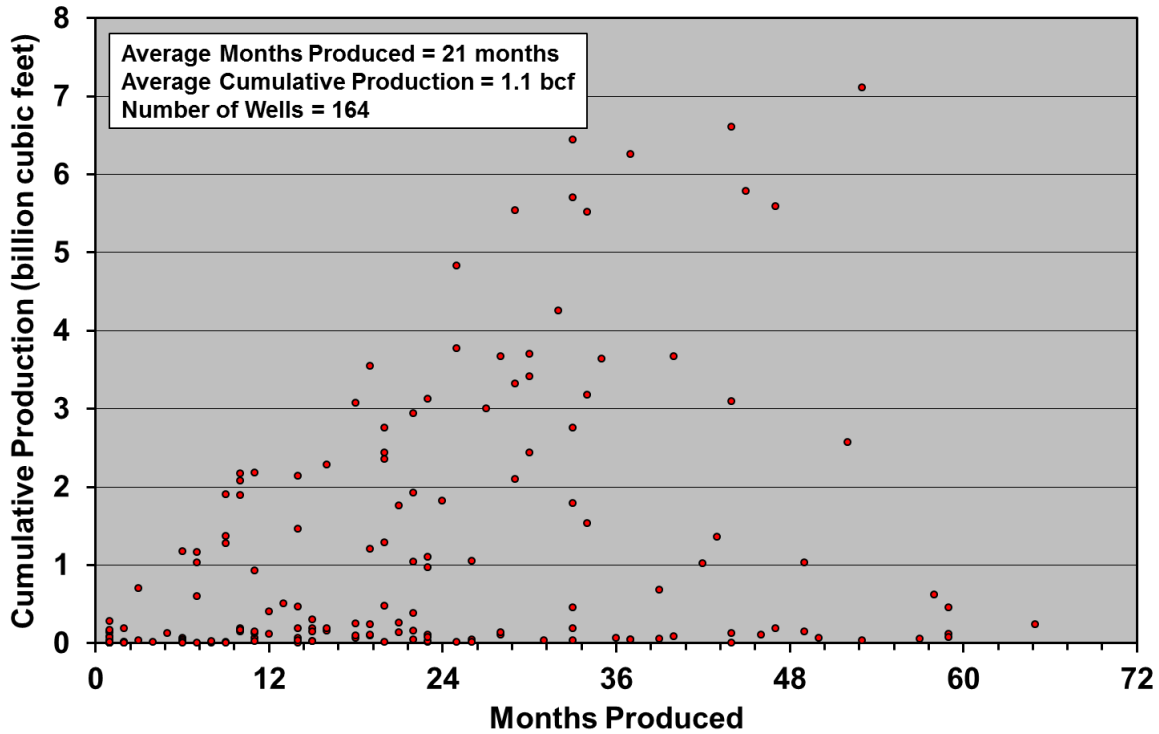


**Figure 3-32. Average first-year production rates for Haynesville horizontal and vertical/directional gas wells, 2009 to 2013.<sup>50</sup>**

Average well quality is flat in the most recent year after rising significantly in the early years of the play.

<sup>50</sup> Data from Drillinginfo retrieved August 2014.

Another measure of well quality is cumulative production and well life. Nearly 5% of the wells that have been drilled in the Haynesville are no longer productive. Figure 3-33 illustrates the cumulative production of these shut-down wells over their lifetime. At a mean lifetime of 21 months and a mean cumulative production of 1.1 billion cubic feet, many of these wells would be economic losers, although wells that produced more than three billion cubic feet were likely economic despite their short lifespan.



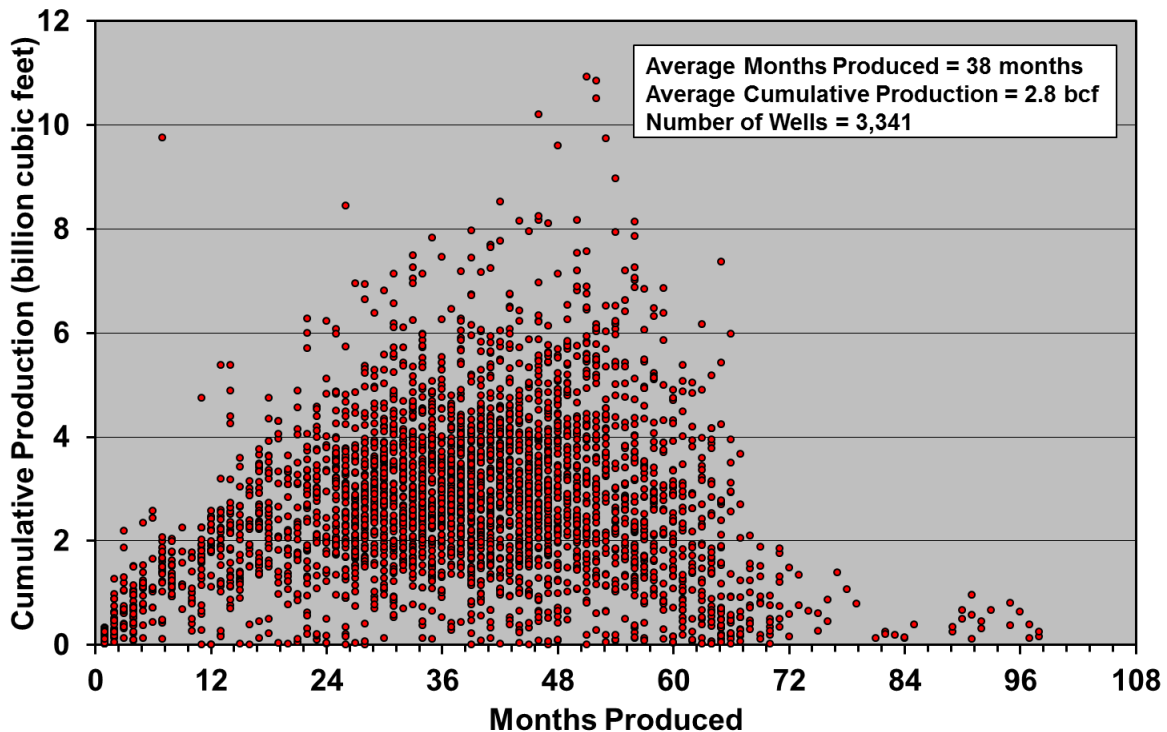
**Figure 3-33. Cumulative gas production and length of time produced for Haynesville wells that were not producing as of February 2014.<sup>51</sup>**

These well constitute nearly 5% of all horizontal wells drilled; many would be economic failures, given the mean life of 21 months and average cumulative production of 1.1 billion cubic feet when production ended.

<sup>51</sup> Data from Drillinginfo retrieved August 2014.

Figure 3-34 illustrates the cumulative production of all wells that were producing in the Haynesville in March 2014. Roughly 18% of the wells have produced more than 4 billion cubic feet over a relatively short lifespan and are clearly economic; however, 33% have yet to produce 2 billion cubic feet. The average well has produced 2.8 billion cubic feet over a lifespan averaging 38 months. Just 8% of these wells are more than 5 years old.

The lifespan of wells is another key parameter as many operators assume a minimum life of 30 years and longer; this is conjectural at this point given the lack of long-term production data.

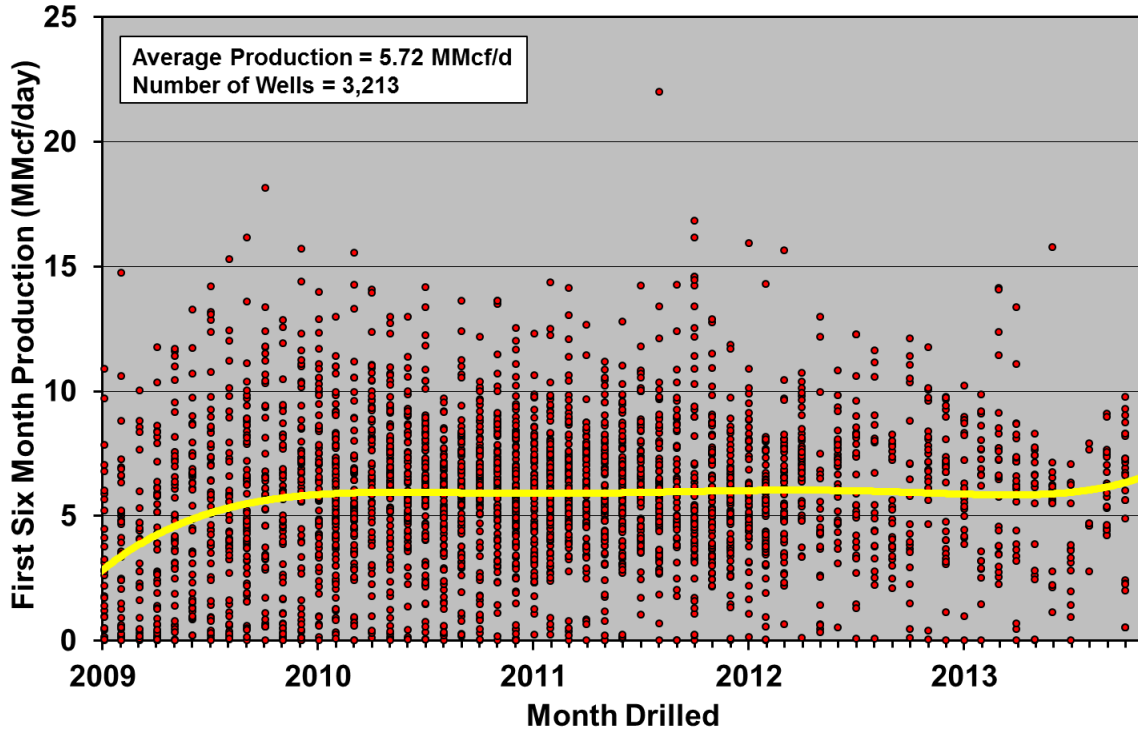


**Figure 3-34. Cumulative gas production and length of time produced for Haynesville wells that were producing as of March 2014.<sup>52</sup>**

These well constitute 95% of all wells drilled. Very few wells are greater than five years old, with a mean age of 38 months and a mean cumulative recovery of 2.8 billion cubic feet.

<sup>52</sup> Data from Drillinginfo retrieved August 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells is not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality, independent of age, is initial productivity (IP), which is often focused on by operators. Figure 3-35 illustrates the average daily output over the first six months of production for all wells in the Haynesville play (six month IP). Again, as with cumulative production, there are a few exceptional wells—3% produced more than 12 million cubic feet per day (MMcf/d)—but the average for all wells drilled since 2009 is 5.72 MMcf/d. Figure 3-27 illustrates the distribution of IPs in map form.

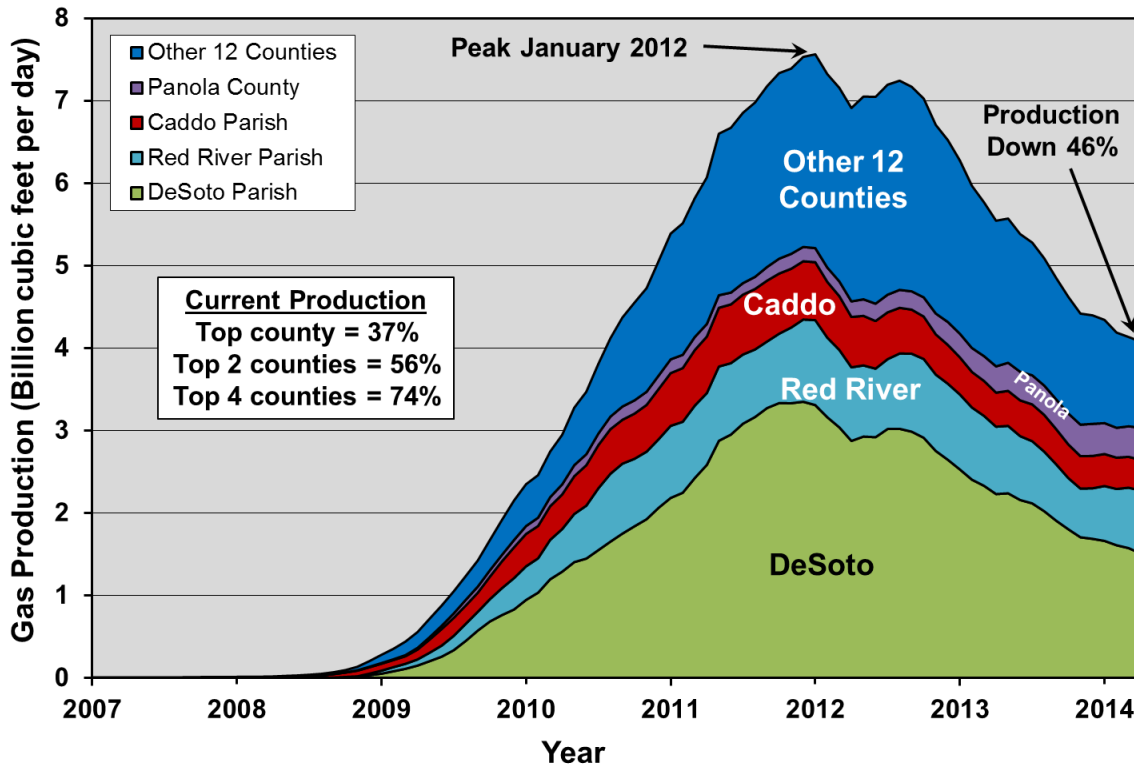


**Figure 3-35. Average gas production over the first six months for all wells drilled in the Haynesville play, 2009 to 2014.<sup>53</sup>**

Although there are a few exceptional wells, the average well produced 5.48 million cubic feet per day over this period. The trend line indicates mean productivity over time

<sup>53</sup> Data from Drillinginfo retrieved August 2014.

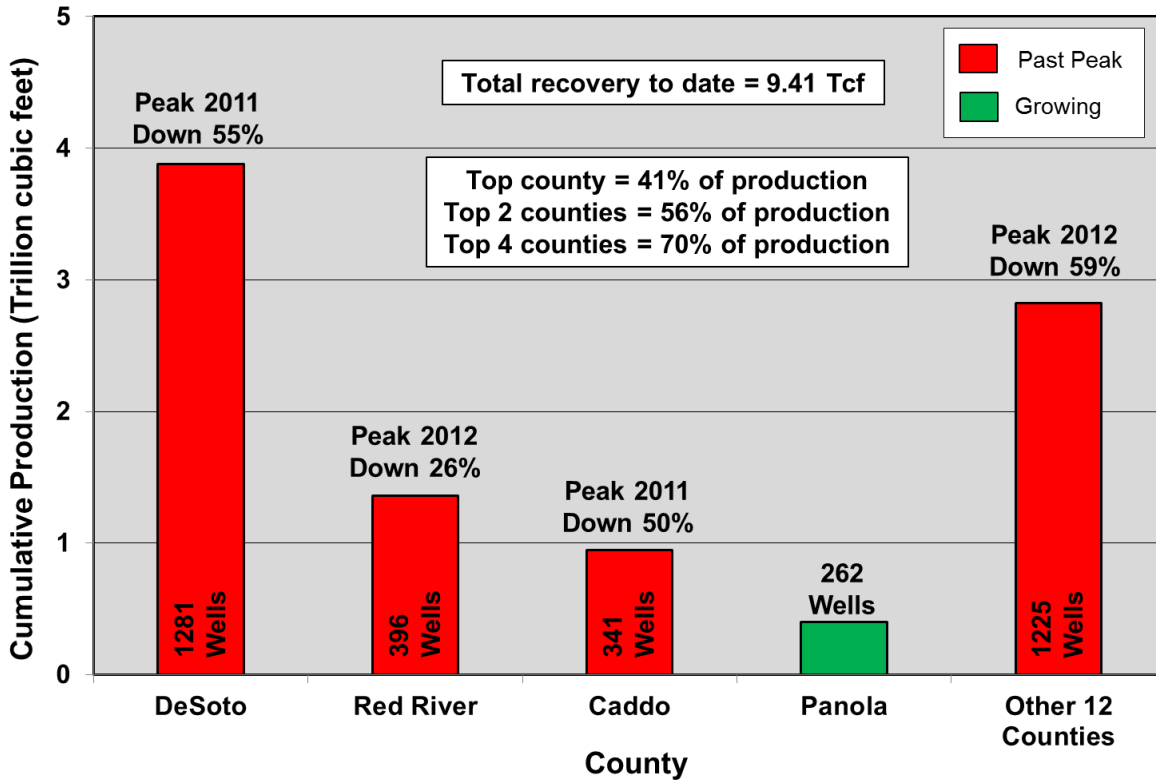
Different counties in the Haynesville display different well quality characteristics which are critical in determining the most likely production profile in the future. Figure 3-36, which illustrates production over time by county, shows that, as of April 2014, the top two counties produced 56% of the total, the top four produced 74%, and the remaining 12 counties produced just 26%.



**Figure 3-36. Gas production by county in the Haynesville play, 2007 through 2014.<sup>54</sup>**  
 The top four counties produced 74% of production in April 2014.

<sup>54</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 3-37, the top two counties have produced 56% of the gas and the top four have produced 70%. All of the counties except Panola in Texas have peaked although with increased drilling rates some could conceivably resume production growth. Production in the top county—DeSoto—is down 55% from peak and production in the other counties is down from 26% to 59%.

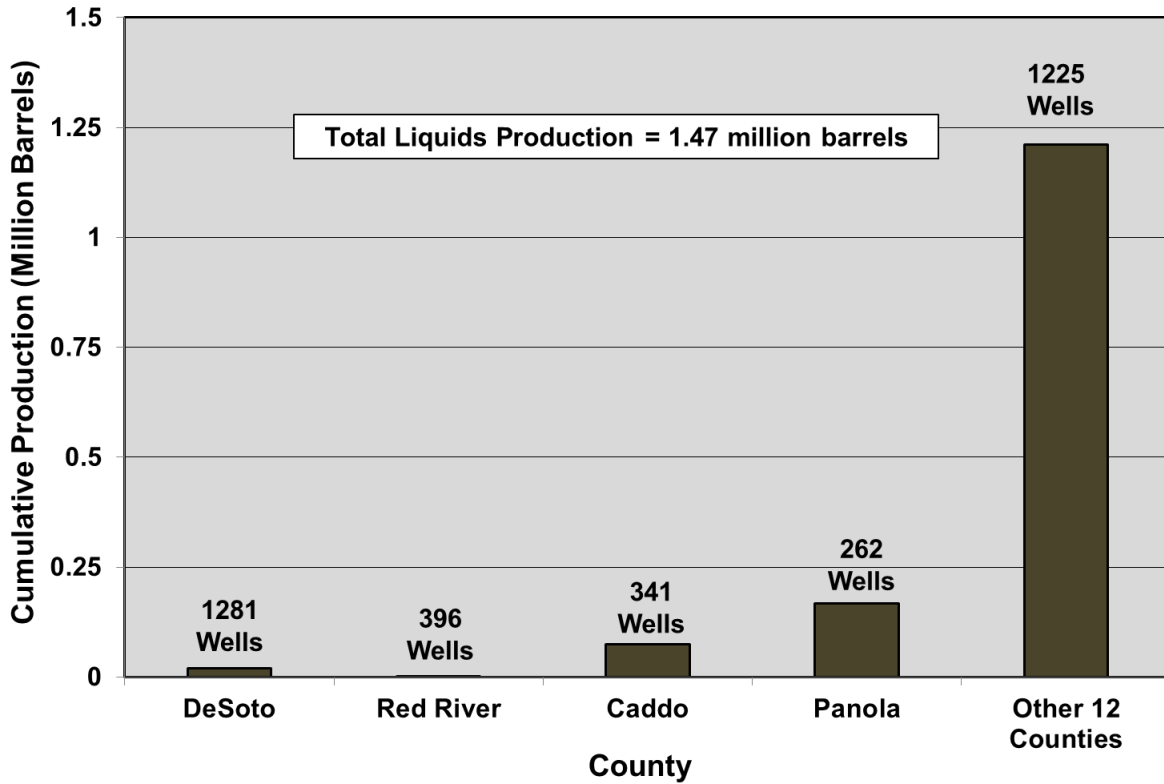


**Figure 3-37. Cumulative gas production by county in the Haynesville play through 2014.**  
 The top four counties have produced 70% of the 9.4 trillion cubic feet of gas produced to date.<sup>55</sup>

<sup>55</sup> Data from Drillinginfo retrieved August 2014.



The Haynesville also produces very limited amounts of natural gas liquids and oil. Most liquids production is not within the top four counties as illustrated in Figure 3-38. Some 1.5 million barrels of liquids have been produced since 2006, and although it has somewhat improved economics in marginal counties for gas production, in the big picture liquids production from the Haynesville is insignificant.

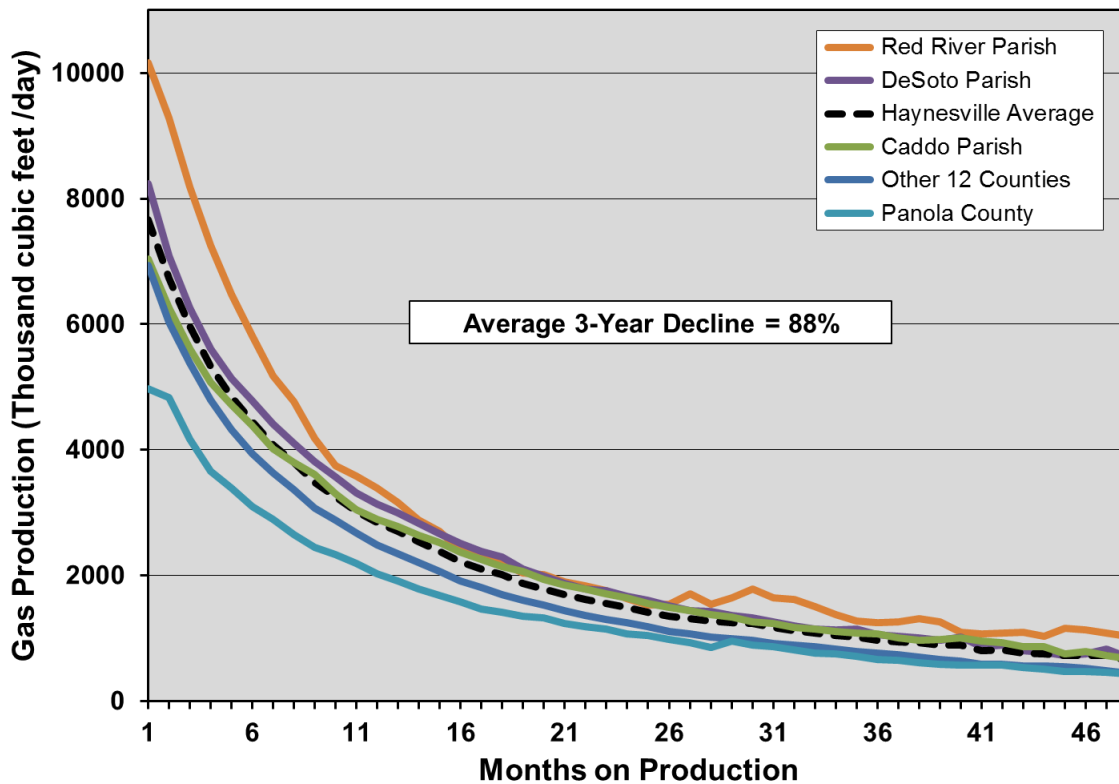


**Figure 3-38. Cumulative liquids production by county in the Haynesville play through 2014.**

The “other 12” counties account for 82% of the 1.5 million barrels produced to date.<sup>56</sup>

<sup>56</sup> Data from Drillinginfo retrieved August 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost on the order of \$9 million or more each<sup>57</sup>, not including leasing costs and other expenses. The areas of highest quality—the “core” or “sweet spots”—have now been well defined. Figure 3-39 illustrates average well decline curves by county, which are a measure of well quality. Initial well productivities (IPs) are more closely grouped than in the Barnett, however the top producing counties—DeSoto and Red River in Louisiana,—which are in steep decline—are significantly better than Panola County in Texas, which is the only county growing in production. There are still a significant number of locations in which to drill wells in the top producing counties, although the overall play area of the Haynesville is smaller than plays like the Barnett and is dwarfed by the Marcellus.<sup>58</sup>



**Figure 3-39. Average horizontal gas well decline profiles by county for the Haynesville play.**

The top two counties, which have produced much of the gas in the Haynesville, are clearly superior.<sup>59</sup>

Another measure of well quality is “estimated ultimate recovery” or EUR—the amount of gas a well will recover over its lifetime. To be clear, no one knows what the lifespan of an average Haynesville well is, given that few of them are more than five years old (see Figure 3-33 and Figure 3-34), and some 5% of wells drilled have ceased production at an average age of under two years. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-39, assuming well life spans of 30-50 years (as is typical for conventional wells), but so far this is speculation given the nature of the extremely low permeability

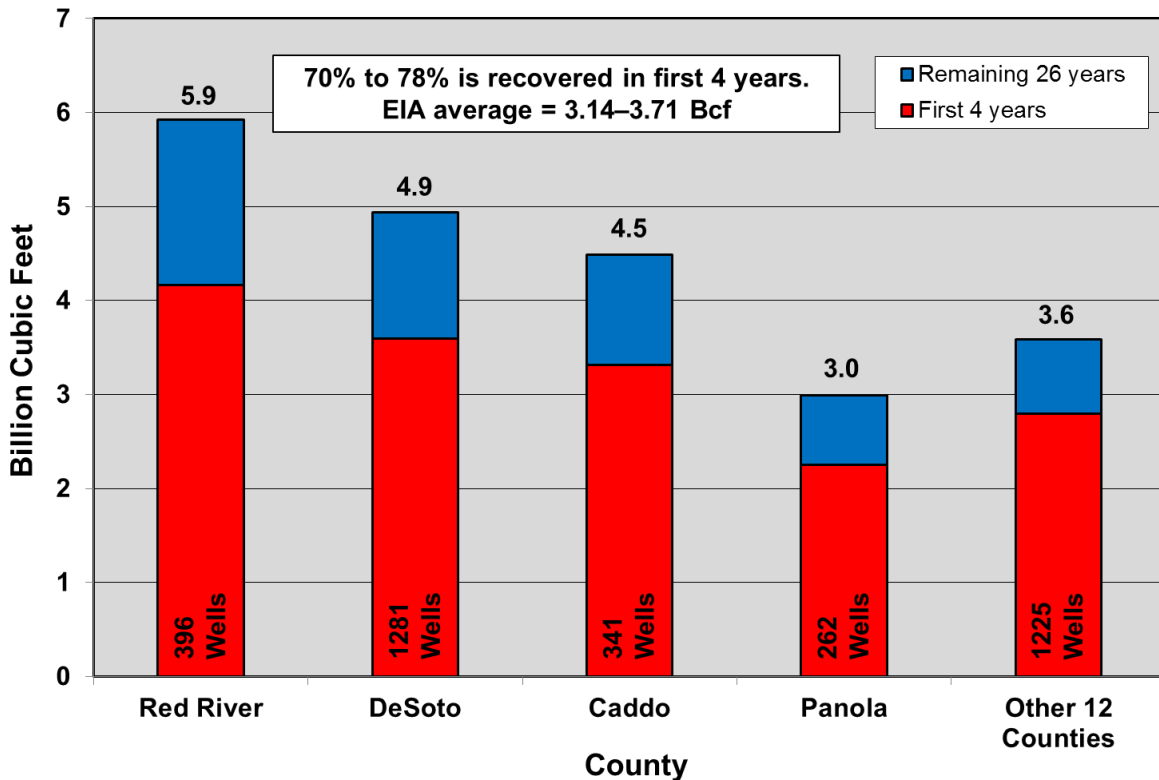
<sup>57</sup>Mark J. Kaiser, June 2014, *Oil and Gas Journal*, “HAYNESVILLE UPDATE–2: North Louisiana drilling costs vary slightly 2007-12,” <http://www.ogj.com/articles/print/volume-112/issue-1/exploration-development/north-louisiana-drilling-costs-vary-slightly-2007-12.html>.

<sup>58</sup>EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>59</sup>Data from Drillinginfo retrieved August 2014.

reservoirs and the completion technologies used in the Haynesville. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-39, which exhibits steep initial decline with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-40 illustrates theoretical EURs by county for the Haynesville for comparative purposes of well quality. These range from 3.0 to 5.9 billion cubic feet per well, which agrees fairly well with the 3.14 to 3.71 billion cubic feet assumed by the EIA.<sup>60</sup> The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 70% and 78% of an average well's lifetime production occurs in the first four years.



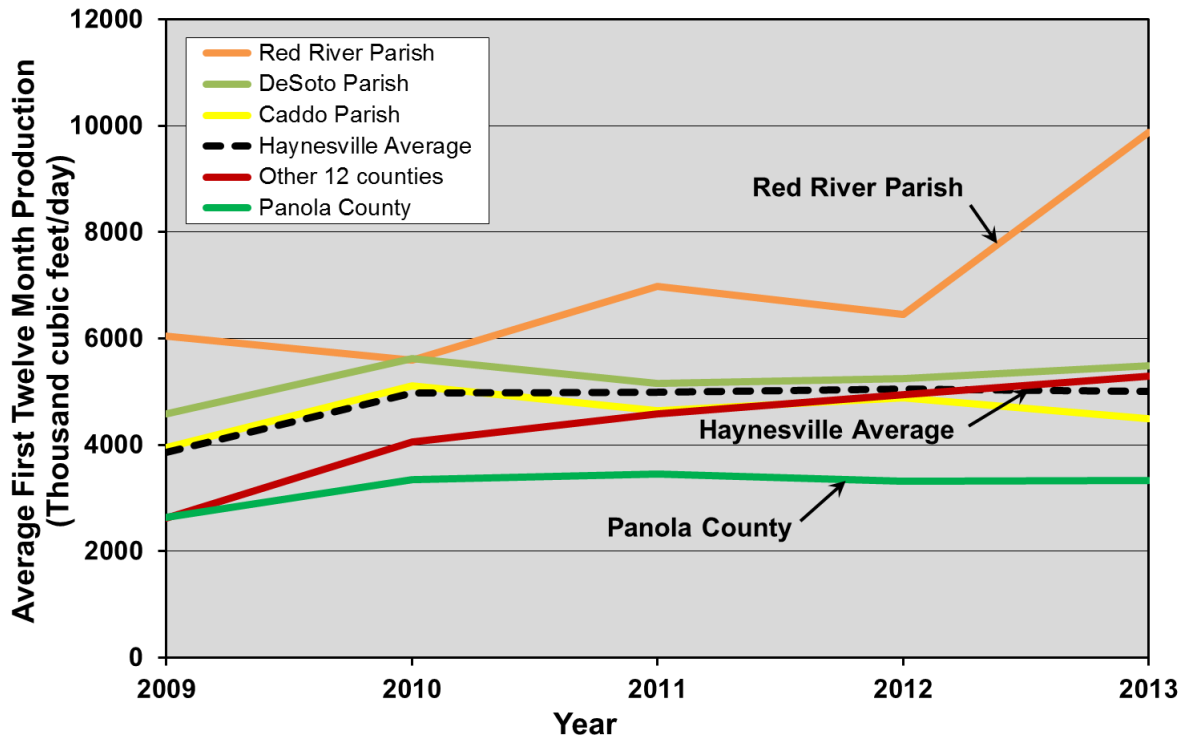
**Figure 3-40. Estimated ultimate recovery of gas per well by county for the Haynesville play.<sup>61</sup>**

EURs are based on average well decline profiles (Figure 3-39) and a terminal decline rate of 20%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life.

<sup>60</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>61</sup> Data from Drillinginfo retrieved August 2014.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the rate of production in the first year of the average well and the field decline rate, we can calculate the number of wells that need to be drilled each year to offset field decline in order to maintain production. Figure 3-41 illustrates the average first-year production rate of wells by county. Notwithstanding significant gains in Red River Parish (which has the smallest prospective area of the top four counties), the average well quality is flat on average and is declining in Caddo Parish.



**Figure 3-41. Average first year gas production rates of wells by county for the Haynesville play, 2009 to 2013.<sup>62</sup>**

Well quality is rising significantly in Red River Parish but is flat on average for the play as a whole. Panola County, which is the only county in which production is rising, had first-year average well production of less than half that of Red River Parish in 2013.

<sup>62</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.2.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Haynesville play. The EIA has estimated the total play area in Louisiana and Texas at 3,419 square miles and suggests this can be drilled at a well density of six per square mile, for a total of 20,511 wells. As 3,505 wells have already been drilled this leaves 17,006 yet-to-drill wells.

Table 3-2 breaks down the number of yet-to-drill wells by county along with other critical parameters used for determining the future production rates of the Haynesville play.

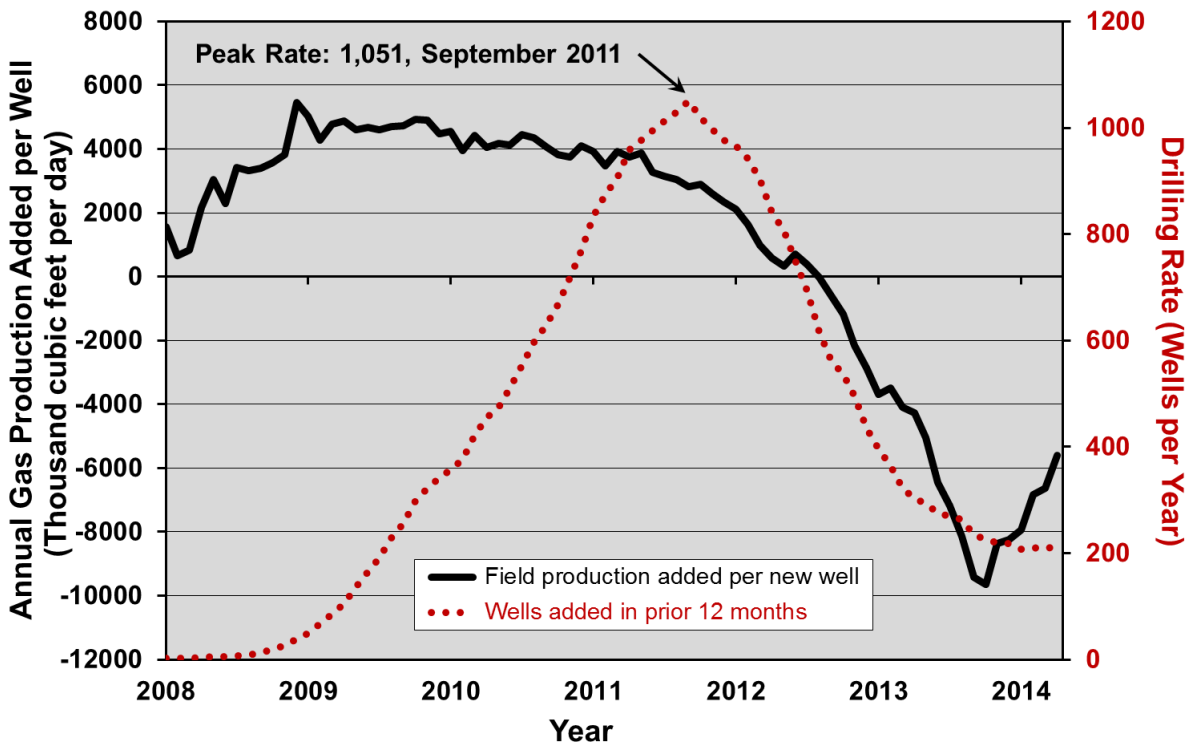
Parameter	County					Total
	Caddo	DeSoto	Panola	Red River	Other 12	
Production April 2014 (Bcf/d)	0.37	1.51	0.39	0.76	1.04	4.08
% of Field Production	9.1	37.1	9.6	18.7	25.6	100.0
Cumulative Gas (Tcf)	0.95	3.88	0.40	1.36	2.82	9.41
Cumulative Liquids (MMBBL)	0.07	0.02	0.17	0.00	1.21	1.47
Number of Wells	341	1281	262	396	1225	3505
Number of Producing Wells	326	1216	243	369	1120	3274
Average EUR per well (Bcf)	4.5	4.9	3	5.9	3.6	4.9
Field Decline (%)	34	50	52	49	50	49
3-Year Well Decline (%)	86	87	87	88	89	88
Peak Month	Sep-11	Dec-11	Rising	Jan-12	Jul-12	Jan-12
% Below Peak	50	55	Rising	29	59	46
Average First Year Production in 2013 (Mcf/d)	4492	5493	3330	9881	5286	5011
New Wells Needed to Offset Field Decline	28	138	61	38	99	399
Area in square miles	937	895	801	402	8000	11035
% Prospective	35	90	90	80	15	31
Net square miles	328	806	721	322	1243	3419
Well Density per square mile	1.04	1.59	0.36	1.23	0.99	1.03
Additional locations to 6/sq. Mile	1627	3552	4063	1534	6230	17006
Population	254969	26656	22756	9091	N/A	N/A
Total Wells 6/sq. Mile	1968	4833	4325	1930	7455	20511
Total Producing Wells 6/sq. Mile	1952	4768	4306	1902	7351	20280

**Table 3-2. Parameters for projecting Haynesville production, by county.**

Area in square miles under "Other" is estimated.

### 3.3.2.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling—the fifth key fundamental. Figure 3-42 illustrates the historical drilling rates in the Haynesville. Horizontal drilling rates peaked in 2011 at 1,051 wells per year and have fallen to current levels of about 200 wells per year. Current drilling rates are only half the 400 wells per year required to maintain production at current levels, hence each new well drilled now serves only to slow the overall production decline of the play. It appears that the drilling rate is stabilizing at 200 wells per year so production will keep falling until this number of wells is sufficient to offset field decline.



**Figure 3-42. Annual gas production added per new horizontal well and annual drilling rate and in the Haynesville play, 2008 through 2014.<sup>63</sup>**

Drilling rate peaked in 2011 and is now far below the level needed to keep production flat, hence each new well now only serves to slow the overall production decline of the play.

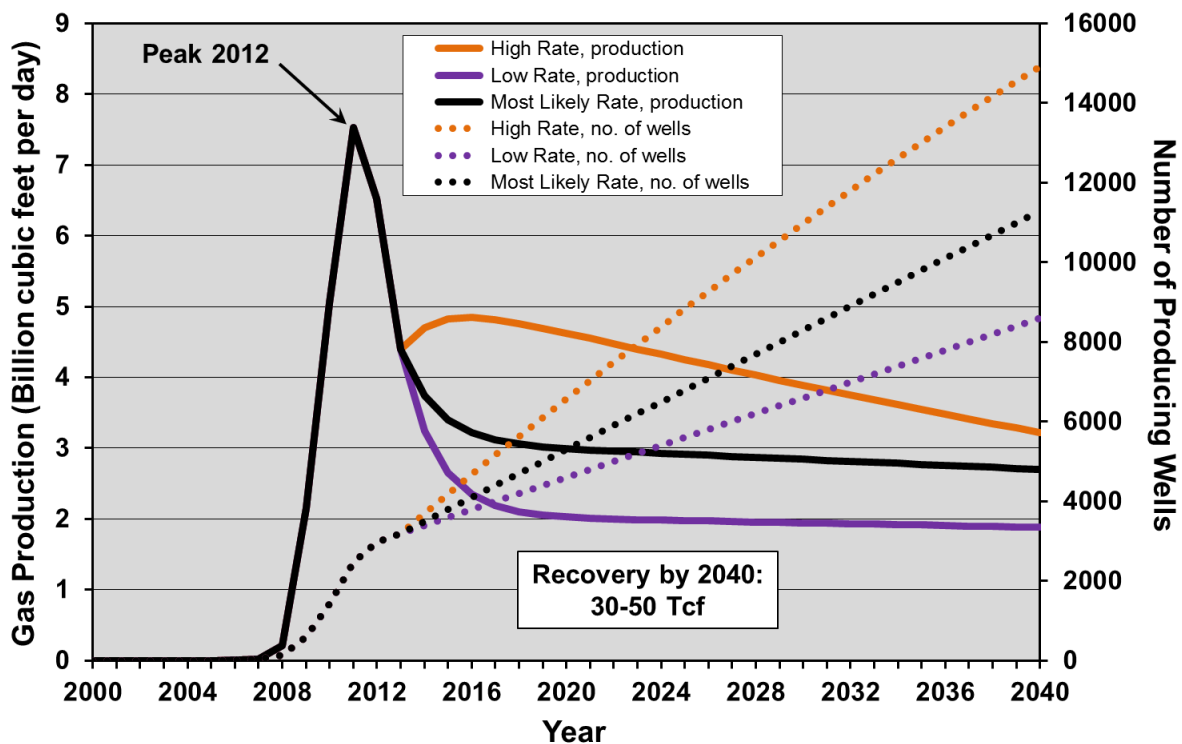
<sup>63</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

### 3.3.2.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Haynesville play were developed to illustrate the effects of changing the rate of drilling. Figure 3-43 illustrates the production profiles of three drilling rate scenarios if 100% of the prospective play area is drillable at six wells per square mile (the EIA estimate of well density as well as drillable area<sup>64</sup>). These scenarios are:

1. MOST LIKELY RATE scenario: Drilling increases by 50% from the current rate to 300 wells per year.
2. LOW RATE scenario: Drilling remains at the current rate of 200 wells per year and holds constant.
3. HIGH RATE scenario: Drilling more than doubles to 500 wells per year, then gradually declines to 300 wells per year.

In all of these scenarios there are sufficient drilling locations to maintain drilling beyond 2040.



**Figure 3-43. Three drilling rate scenarios of Haynesville gas production (assuming 100% of the area is drillable at six wells per square mile).<sup>65</sup>**

“Most Likely Rate” scenario: drilling increases to 300 wells/year, holding constant.

“Low Rate” scenario: drilling holds constant at 200 wells/year.

“High Rate” scenario: drilling increases to 500 wells/year, declining to 300 wells/year.

<sup>64</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>65</sup> Data from Drillinginfo retrieved August 2014.

The drilling rate scenarios have the following results:

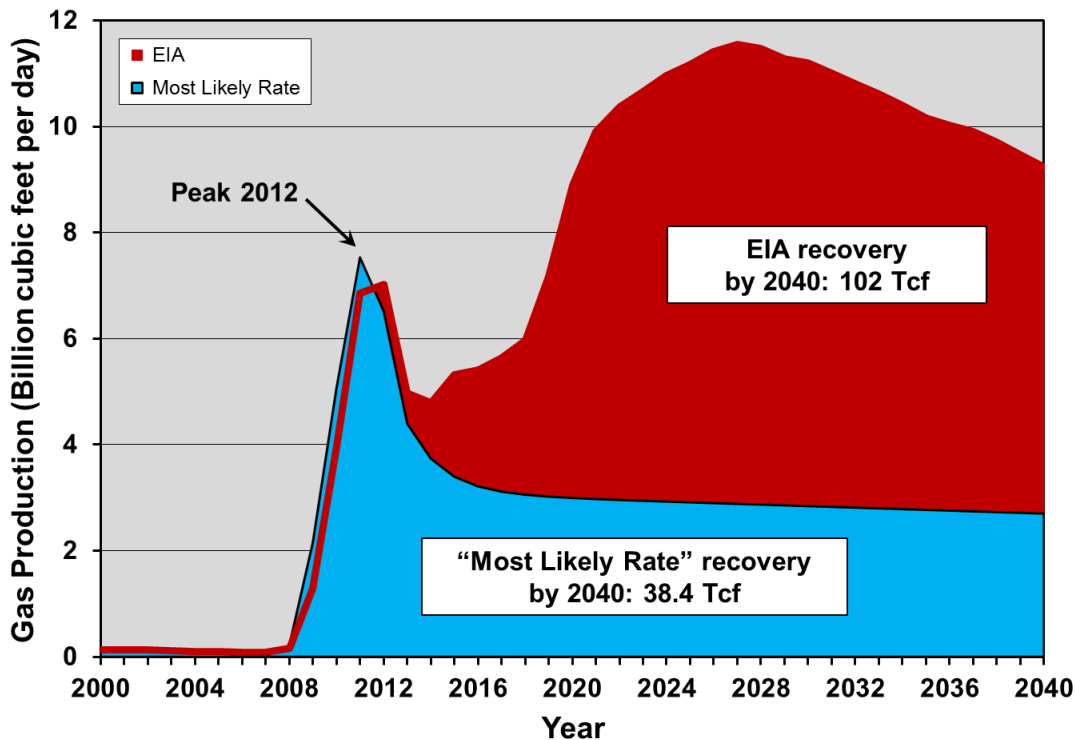
1. **MOST LIKELY RATE** scenario: Production will continue to fall until it stabilizes at about 3 billion cubic feet per day—less than half of the Haynesville’s peak rate. Total gas recovery by 2040 would be 38.4 trillion cubic feet and drilling would continue beyond 2040.
2. **LOW RATE** scenario: Production will continue to fall until stabilizing at about 2 billion cubic feet per day—less than a third of peak production rates. Total gas recovery by 2040 would be 29.7 trillion cubic feet and drilling would continue beyond 2040.
3. **HIGH RATE** scenario: Production decline in the Haynesville could be temporarily reversed and grow somewhat in the short term. Total gas recovery by 2040 would be 49.8 trillion cubic feet and drilling would continue beyond 2040.

Total recovery of 38.4 trillion cubic feet by 2040 in the “Most Likely Rate” scenario is four times what has been recovered so far in the Haynesville, and in the “High Rate” scenario as much as 49.8 trillion cubic feet could be recovered; however, production rates would be far below those projected by the EIA for the Haynesville play.



### 3.3.2.7 Comparison to EIA Forecast

Figure 3-44 illustrates the EIA's projection for Haynesville production through 2040 compared to the "Most Likely Rate" scenario. The EIA projects a recovery by 2040 of 102 Tcf to meet its reference case forecast, and projects a new peak of the play in 2027 at a level far higher than the early-2012 peak. This represents the recovery of 110% of both proved reserves<sup>66</sup> and unproved resources.<sup>67</sup> Furthermore, the EIA projects that production in 2040 will be higher than the 2012 peak, suggesting that vastly more gas will be recovered beyond 2040. This strains credibility to the limit. How can all the proved and unproved resources and reserves be extracted and still have production above all-time highs in 2040?



**Figure 3-44. "Most Likely Rate" scenario of Haynesville gas production compared to the EIA reference case, 2000 to 2040.<sup>68</sup>**

The EIA assumes the Haynesville will reach a new all-time high by 2027, produce 110% of proved reserves and unproved resources by 2040, and presumably produce a great deal more gas in the post-2040 period. . The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis.

<sup>66</sup> EIA, 2014, "Principal shale gas plays: natural gas production and proved reserves, 2011-12," [http://www.eia.gov/naturalgas/crudeoilreserves/excel/table\\_4.xls](http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls).

<sup>67</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>68</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

### 3.3.2.8 Haynesville Play Analysis Summary

Several things are clear from this analysis:

1. Drilling rates have fallen markedly in the Haynesville due to gas prices, although there are still locations to drill in the sweet spots.
2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. The Haynesville field decline rate of 49% is the highest observed in any shale gas play. Current drilling rates of 200 wells per year are just half of the level required to maintain production. Maintaining production at current levels would require the investment of \$3.6 billion per year for drilling (assuming \$9 million per well). Future production profiles are most dependent on drilling rate and, to a lesser extent, on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Maintaining or growing production in the Haynesville would require considerably higher gas prices to justify higher drilling rates.
3. More than doubling current drilling rates could reverse the current production decline temporarily and raise production somewhat, but nowhere near its early 2012 peak. Cumulative recovery by 2040 in this high drilling rate scenario would be increased by 30% over the “Most Likely Rate” scenario but would still be less than half that projected by the EIA in its reference case.
4. The projected recovery of 38.4 Tcf by 2040 in the “Most Likely Rate” scenario represents four times as much gas as has been recovered so far from the Haynesville, yet is only 38% of the 102 Tcf projected by the EIA in its reference case forecast.
5. This report’s projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained. They also assume that 100% of the prospective area is drillable. This is not a sure thing as drilling in the poorer quality parts of the play will require higher gas prices to be economic. Failure to increase current drilling rates will result in a steeper drop off in production.
6. Nearly four times the current number of wells will need to be drilled to meet the production projection of the “Most Likely Rate” scenario by 2040.
7. The EIA projection for future Haynesville gas production included in its reference case forecast for AEO 2014,<sup>69</sup> which forecasts recovery of 110% of proved reserves plus unproved resources by 2040, strains credibility to the limit. It is highly unlikely to be realized, especially at the gas prices the EIA forecasts.<sup>70</sup>

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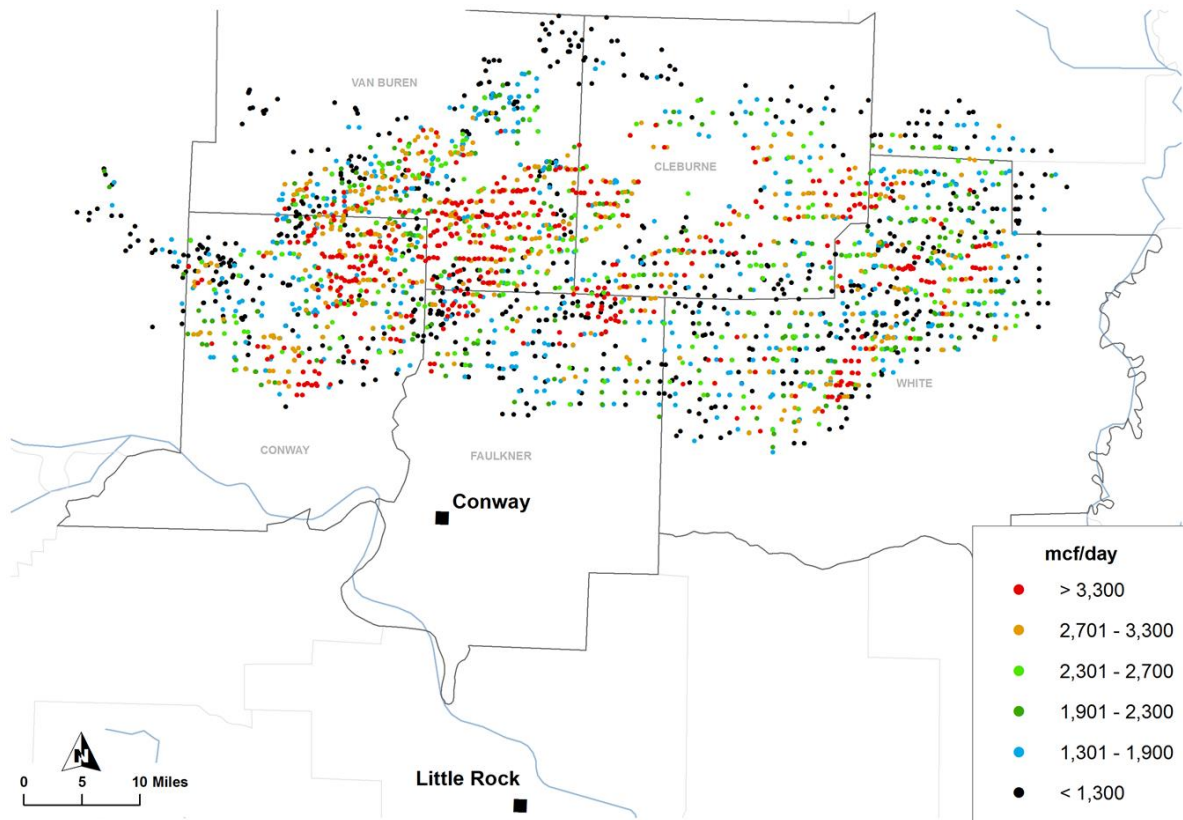
<sup>69</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>70</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/>.

### 3.3.3 Fayetteville Play

The EIA forecasts recovery of 41.5 Tcf of gas from the Fayetteville play by 2040. The analysis of actual production data presented below suggests that this forecast is highly unlikely to be realized.

The Fayetteville play was discovered in Arkansas in 2005 and production grew rapidly until its peak in late 2012. Since that time it has been on an undulating production plateau with production down just over 2% since peak. Figure 3-45 illustrates the distribution of wells as of early 2014. Nearly 5,300 wells have been drilled to date of which 4,914 were producing at the time of writing. The play covers parts of 10 counties although most of the drilling is concentrated in Cleburne, Conway, Faulkner, Van Buren and White counties.

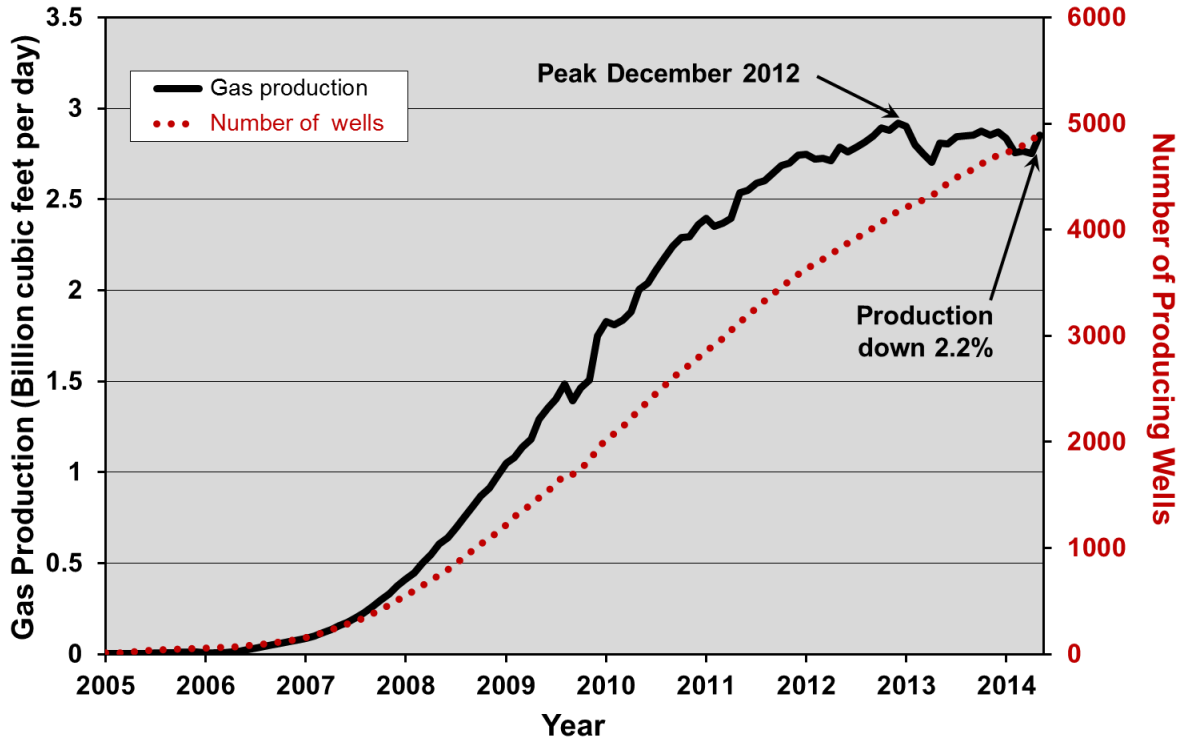


**Figure 3-45. Distribution of wells in the Fayetteville play as of early 2014, illustrating highest one-month gas production (initial productivity, IP).<sup>71</sup>**

Well IPs are categorized approximately by percentile; see Appendix.

<sup>71</sup> Data from Drillinginfo retrieved April 2014.

Production in the Fayetteville peaked at nearly 3 billion cubic feet per day in December 2012 as illustrated in Figure 3-46. Ninety-nine percent of current production is from horizontal fracked wells. Horizontal drilling grew from virtually nothing in 2006 to a peak rate of nearly 900 wells per year in late-2010. It has since fallen to 500 wells per year, which is insufficient to offset field decline. Drilling rates required to keep production flat at current production levels are about 600 wells per year.



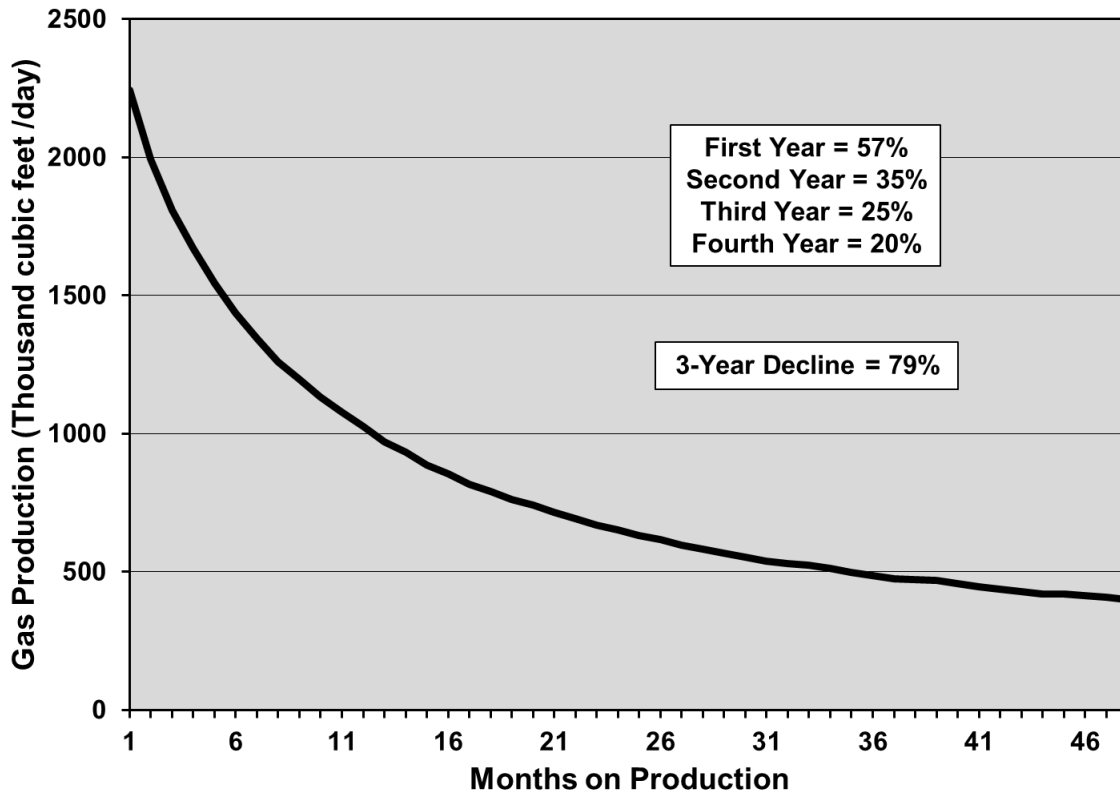
**Figure 3-46. Fayetteville play shale gas production and number of producing wells, 2005 to 2014.<sup>72</sup>**

Gas production data are provided on a “raw gas” basis.

<sup>72</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

### 3.3.3.1 Well Decline

The first key fundamental in determining the life cycle of Fayetteville production is the *well decline rate*. Fayetteville wells exhibit high decline rates in common with all shale plays. Figure 3-47 illustrates the average decline rate of Fayetteville wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The average decline rate over the first three years of well life is 79%, which is well within the typical range of shale plays. Wells are generally more productive than Barnett wells and less so than Haynesville wells. Production is almost exclusively dry gas with no liquids.

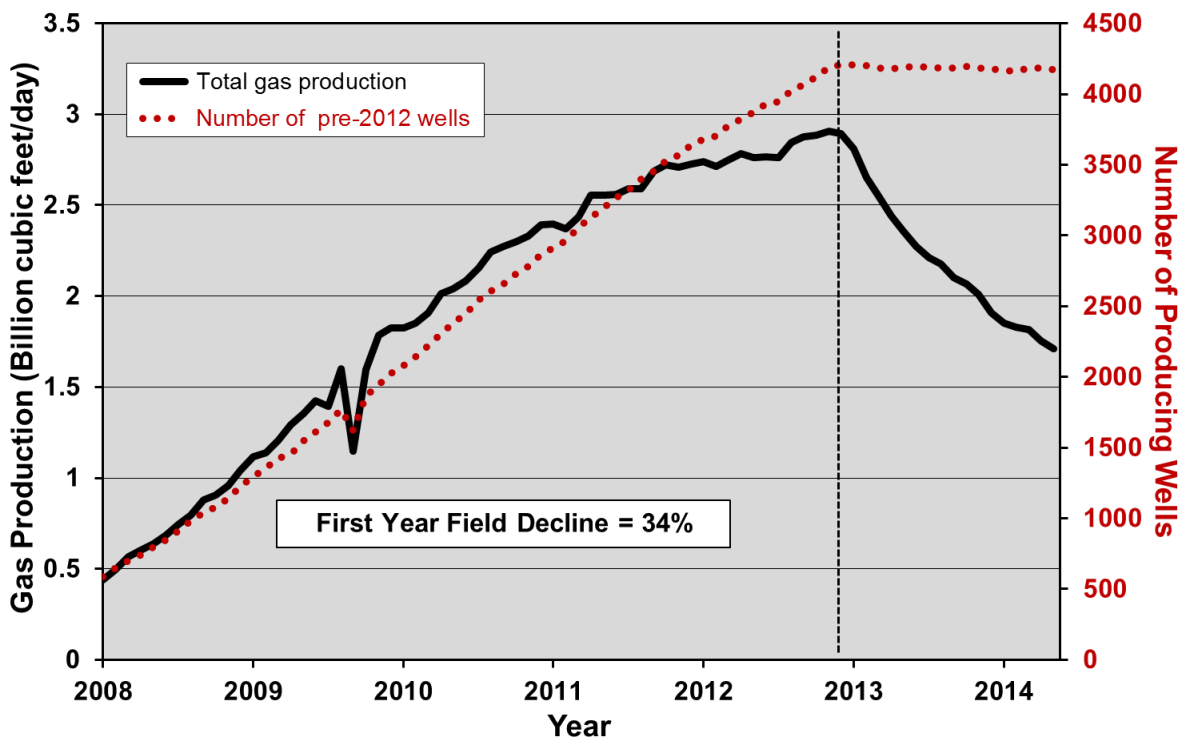


**Figure 3-47. Average decline profile for horizontal gas wells in the Fayetteville play.<sup>73</sup>**  
Decline profile is based on all shale gas wells drilled since 2009.

<sup>73</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.3.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production in the Fayetteville that would be lost in a year without more drilling. Figure 3-48 illustrates production from the 4,200 wells drilled prior to 2013. The first-year decline rate is 34%. This is lower than the well decline rate as the field decline is made up of both new wells declining at high rates and older wells declining at lesser rates. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, approximately 600 new wells each year would be required to offset field decline at current production levels. At an average cost of \$2.4 million per well<sup>74</sup>, this would represent a capital input of about \$1.4 billion per year, exclusive of leasing and other ancillary costs, to keep production flat at 2013 levels. Fayetteville wells are among the cheapest of any shale play and this is likely what has allowed relatively high rates of drilling to be maintained.



**Figure 3-48. Production rate and number of horizontal shale gas wells drilled in the Fayetteville play prior to 2013, 2008 to 2014.<sup>75</sup>**

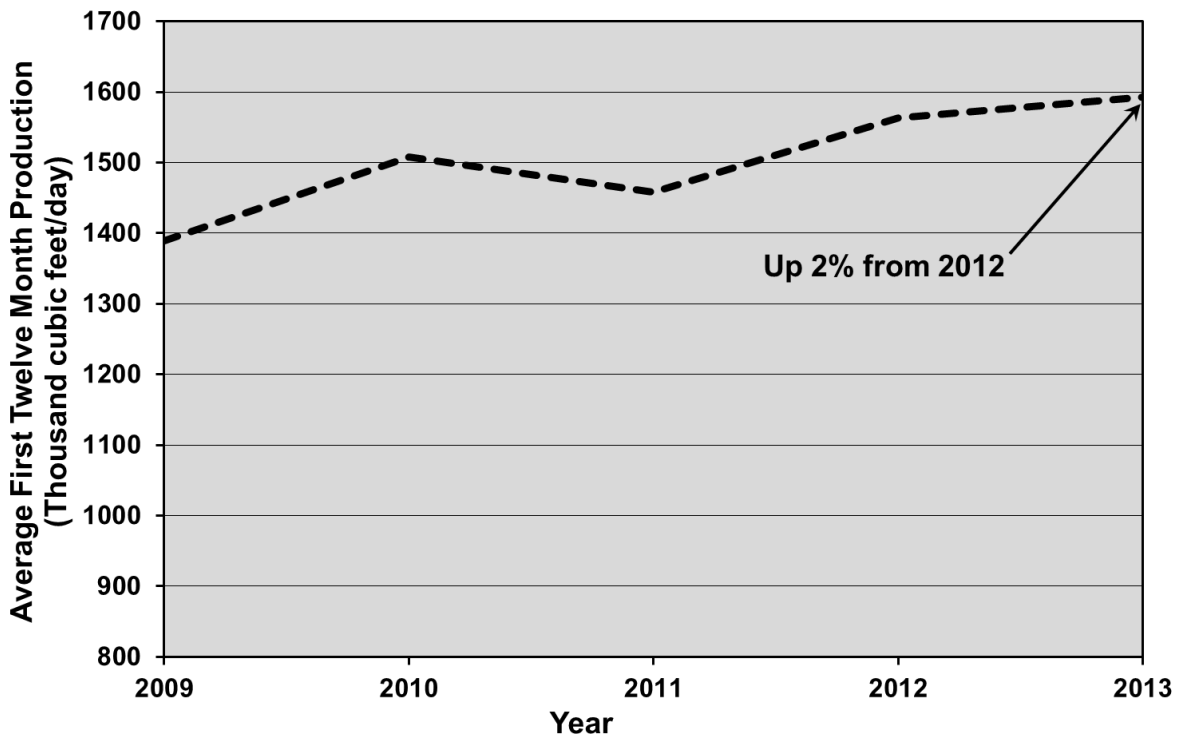
This defines the field decline for the Fayetteville play, which is 34% per year.

<sup>74</sup> Fayetteville Shale, Southwest Energy, 2014, <http://www.swn.com/operations/pages/fayettevilleshale.aspx>.

<sup>75</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.3.3 Well Quality

The third key fundamental is the *average well quality* in the Fayetteville by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. It is, however, approaching the limits of diminishing returns, with average well productivity in the Fayetteville up just 2% in 2013, after rising significantly in the early years of the play, as illustrated in Figure 3-49. Given the propensity of operators to drill their best locations first, the slight increase in average quality may have as much to do with concentrating drilling on the highest quality locations as with improvements in technology.

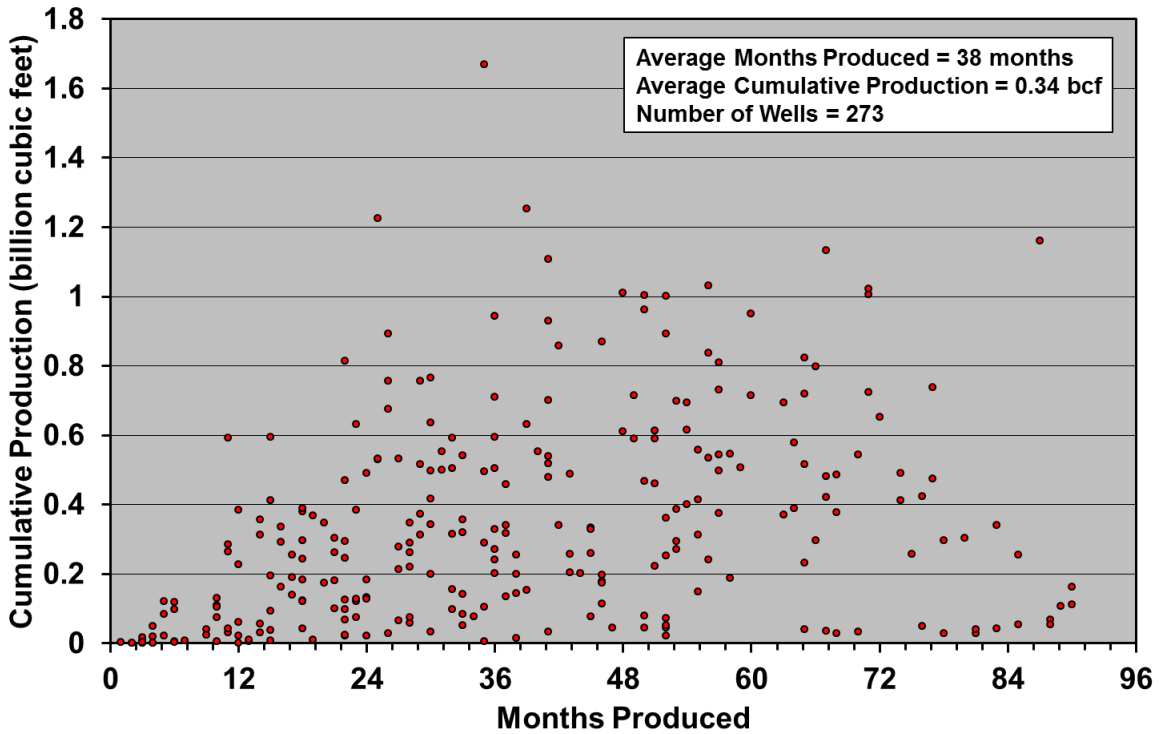


**Figure 3-49. Average first-year production rates for Fayetteville gas wells, 2009 to 2013.<sup>76</sup>**

Average well quality rose slightly in the most recent year.

<sup>76</sup> Data from Drillinginfo retrieved August 2014.

Another measure of well quality is cumulative production and well life. Nearly 8% of the wells that have been drilled in the Fayetteville are no longer productive. Figure 3-50 illustrates the cumulative production of these shut-down wells over their lifetime. At a mean lifetime of 31 months and a mean cumulative production of 0.34 billion cubic feet, most of these wells would be economic losers.



**Figure 3-50. Cumulative gas production and length of time produced for Fayetteville wells that were not producing as of February 2014.<sup>77</sup>**

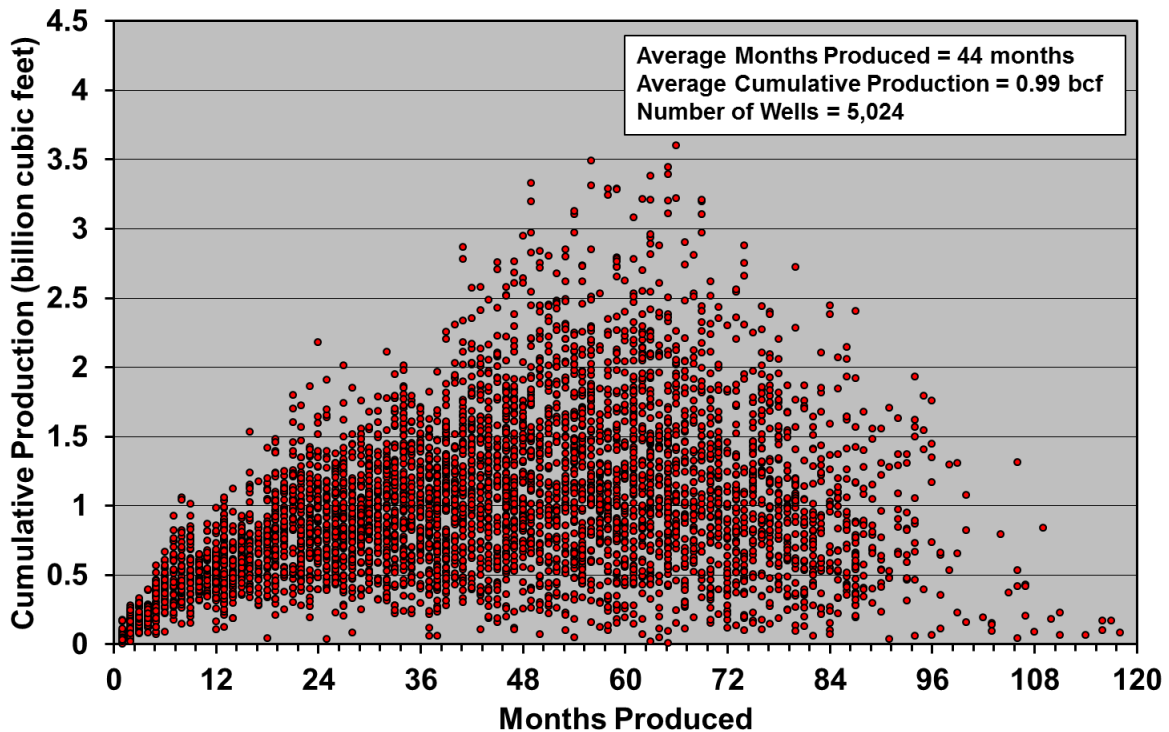
These well constitute nearly 8% of all wells drilled; most would be economic failures, given the mean life of 38 months and average cumulative production of 0.34 billion cubic feet when production ended.

<sup>77</sup> Data from Drillinginfo retrieved August 2014.



Figure 3-51 illustrates the cumulative production of all wells that were producing in the Fayetteville in March 2014. Roughly 6% of the wells have produced more than 2 billion cubic feet over a relatively short lifespan and are clearly economic, however 57% have yet to produce 1 billion cubic feet. The average well has produced 0.99 billion cubic feet over a lifespan of 44 months. Just 5% of these wells are more than 7 years old.

The lifespan of wells is another key parameter as many operators assume a minimum well life of 30 years and longer, though this is conjectural given the lack of long term production data.

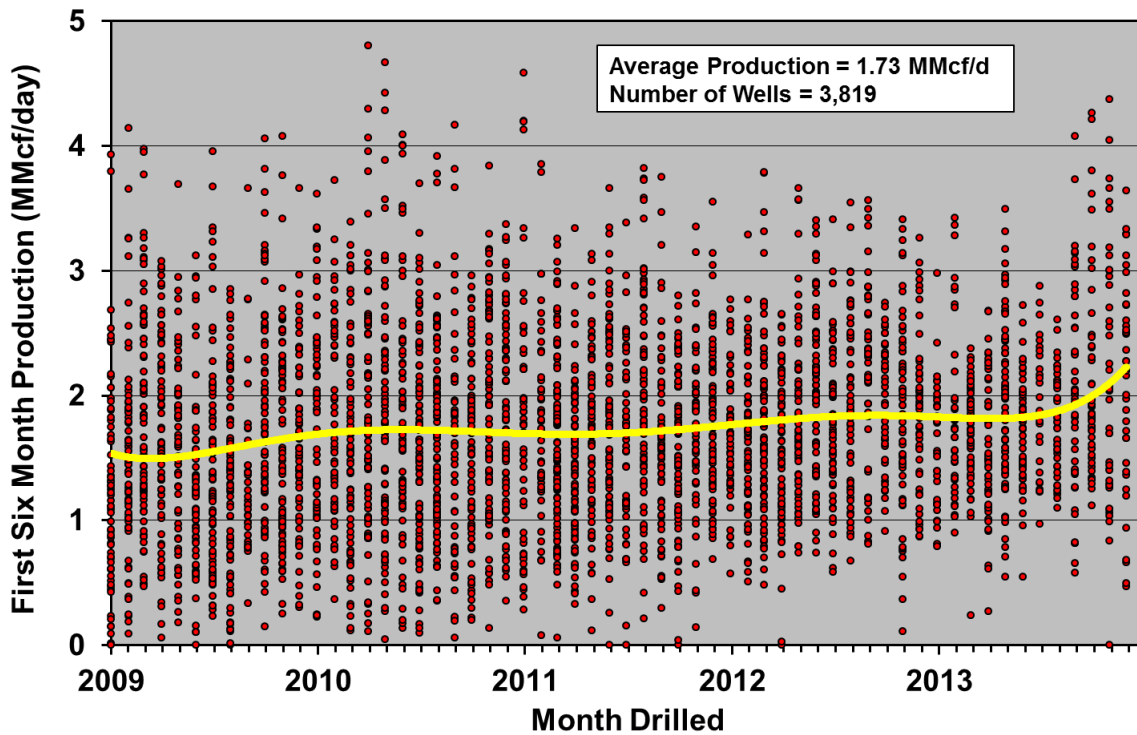


**Figure 3-51. Cumulative gas production and length of time produced for Fayetteville wells that were producing as of March 2014.<sup>78</sup>**

These constitute 92% of all wells drilled. Very few wells are greater than seven years old, with a mean age of 44 months and a mean cumulative recovery of 0.99 billion cubic feet.

<sup>78</sup> Data from Drillinginfo retrieved August 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells is not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality, independent of age, is initial productivity (IP). Figure 3-52 illustrates the average daily output over the first six months of production for all wells in the Fayetteville play (six-month IP). Again, as with cumulative production, there are a few exceptional wells—5% produced more than 3 million cubic feet per day (MMcf/d)—but the average for all wells drilled since 2009 is 1.73 MMcf/d. Figure 3-45 illustrates the distribution of IPs in map form.

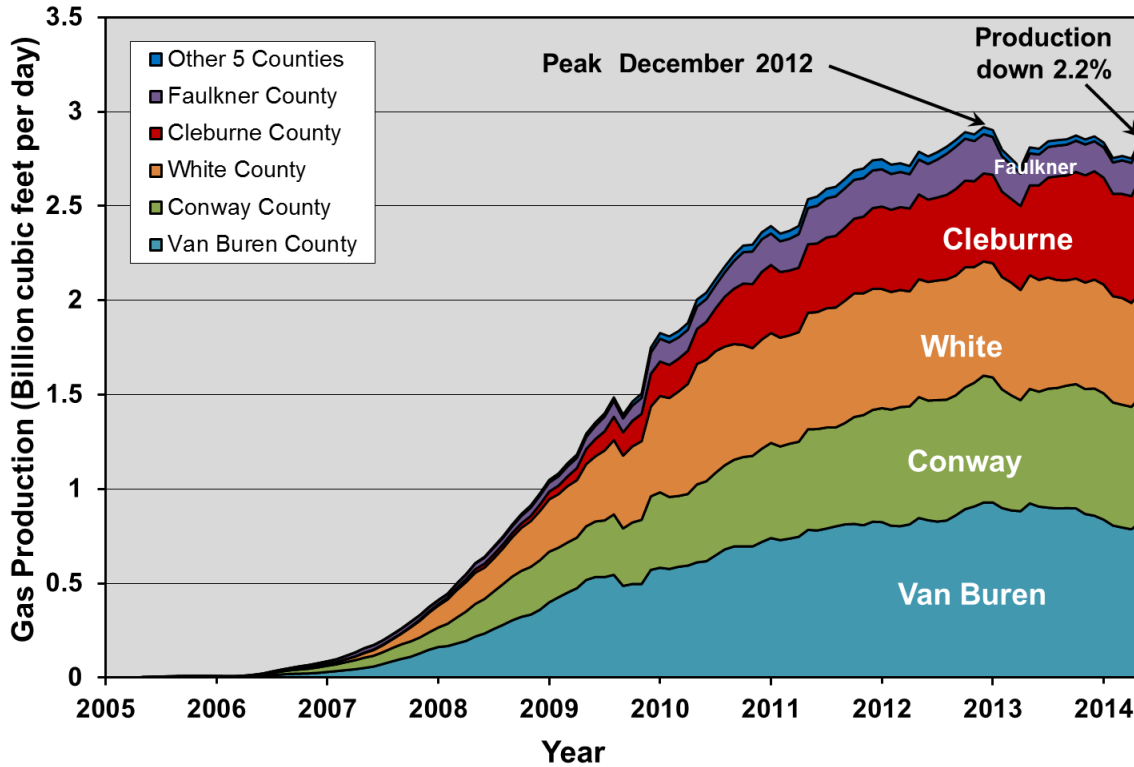


**Figure 3-52. Average gas production over the first six months for all wells drilled in the Fayetteville play, 2009 to 2014.<sup>79</sup>**

Although there are a few exceptional wells, the average well produced 1.73 million cubic feet per day over this period. The trend line indicates mean productivity over the time period.

<sup>79</sup> Data from Drillinginfo retrieved August 2014.

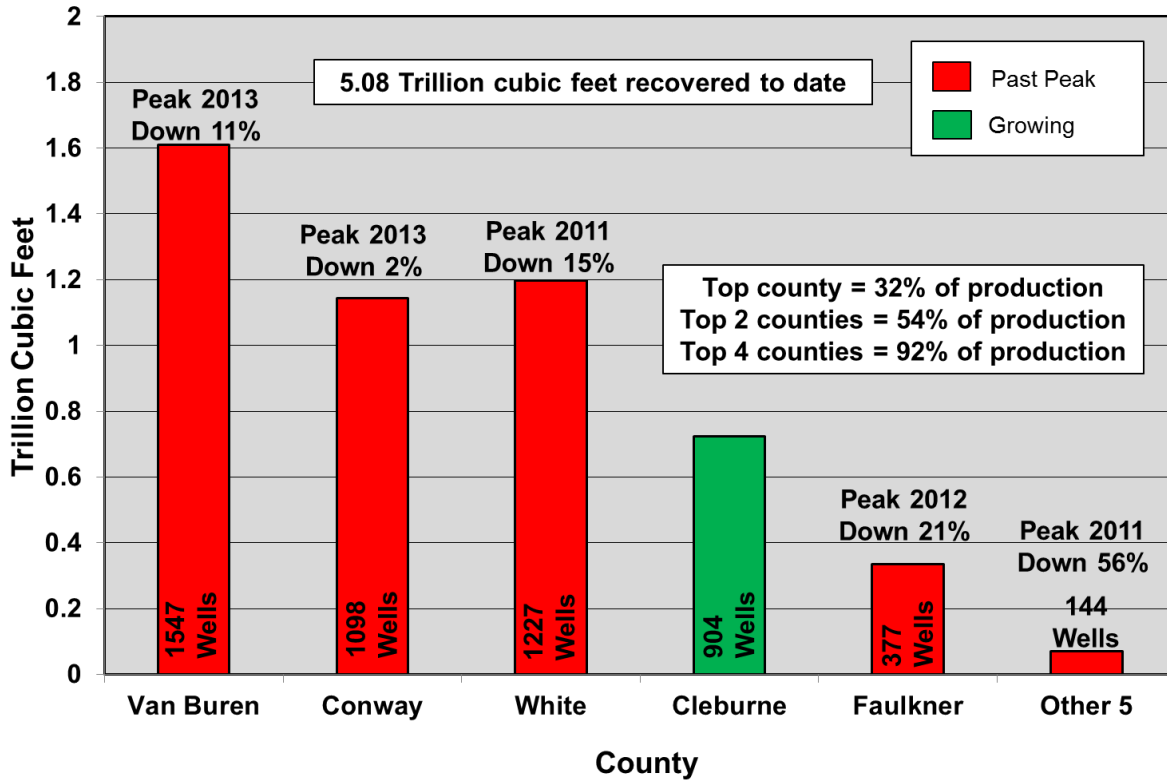
Different counties in the Fayetteville display different well quality characteristics, which are critical in determining the most likely production profile in the future. Figure 3-53, which illustrates production over time by county, shows that, as of May 2014, the top two counties produced 53% of the total, the top four produced 93%, and the remaining 6 counties produced just 7%. All counties are below peak production except Cleburne.



**Figure 3-53. Gas production by county in the Fayetteville play, 2005 through 2014.<sup>80</sup>**  
 The top four counties produced 93% of production in May 2014.

<sup>80</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 3-54, the top two counties have produced 54% of the gas and the top four have produced 92%. All of the counties except Cleburne have peaked, although with increased drilling rates some could conceivably resume production growth. Production in the top county—Van Buren—is down 11% from peak and production in other counties outside of the top four is down from 21 to 56%.

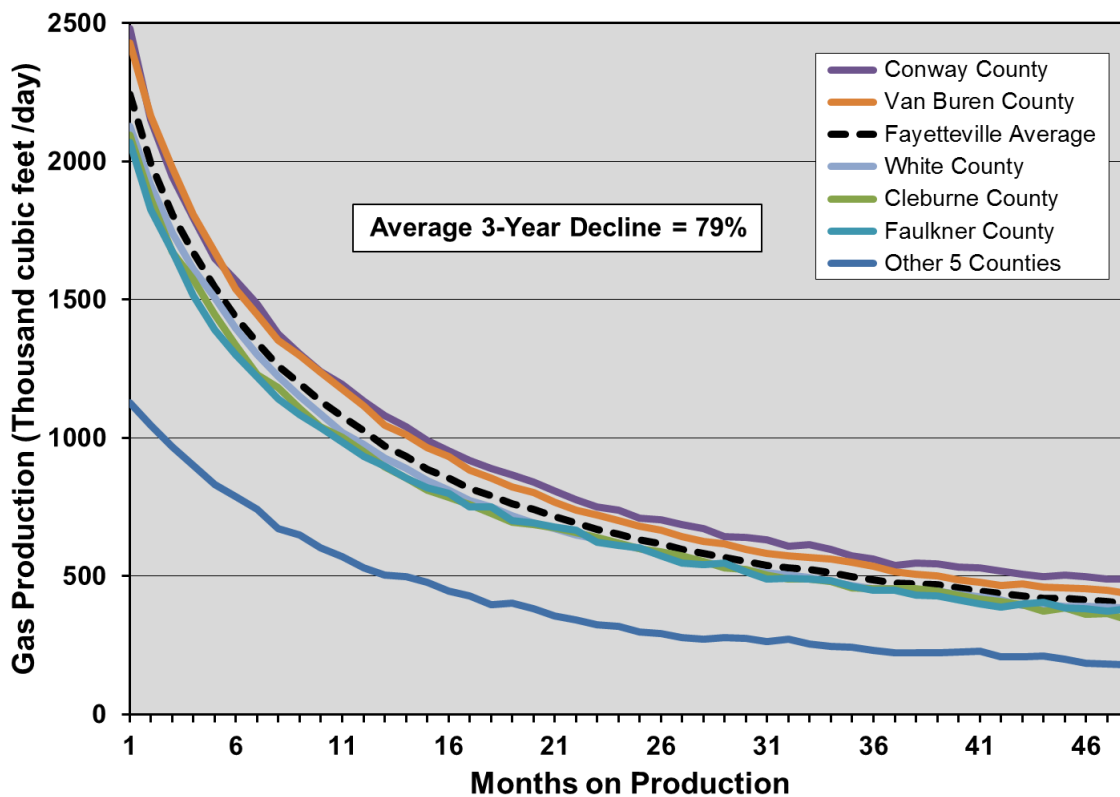


**Figure 3-54. Cumulative gas production by county in the Fayetteville play through 2014.<sup>81</sup>**

The top four counties have produced 92% of the 5.08 trillion cubic feet of gas produced to date.

<sup>81</sup> Data from Drillinginfo retrieved August 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost on the order of \$2.4 million each<sup>82</sup>, not including leasing costs and other expenses. The areas of highest quality—the “core” or “sweet spots”—have now been well defined. Figure 3-55 illustrates average well decline curves by county which are a measure of well quality. Initial well productivities (IPs) are more closely grouped than in the Barnett; however, the top producing counties—Van Buren and Conway, which are both in decline—are somewhat better than the overall Fayetteville average and are significantly better than counties outside the top five. There are still a significant number of locations to drill wells in the top producing counties, although the overall play area of the Fayetteville is much smaller than plays like the Barnett and is dwarfed by the Marcellus.<sup>83</sup>



**Figure 3-55. Average horizontal gas well decline profiles by county for the Fayetteville play.<sup>84</sup>**

The low productivity outside of the top five counties seriously limits expansion of the play.

Another measure of well quality is “estimated ultimate recovery” or EUR—the amount of gas a well will recover over its lifetime. To be clear no one knows what the average lifespan of a Fayetteville well is, given that few of them are more than seven years old (see Figure 3-50 and Figure 3-51), and some 8% of wells drilled have ceased production at an average age of about three years. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-55, assuming well life spans of 30-50 years (as is typical for conventional wells) by comparison to conventional wells, but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Fayetteville.

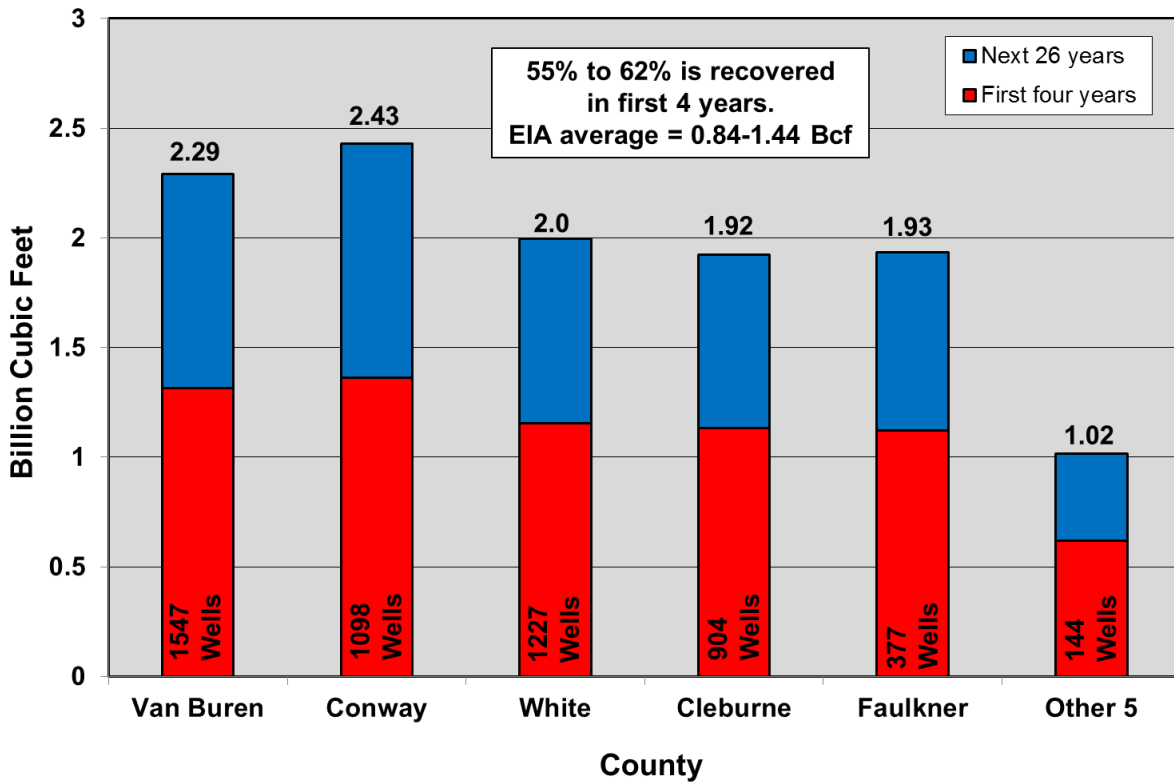
<sup>82</sup> Southwest Energy, 2014, “Fayetteville Shale,” <http://www.swn.com/operations/pages/fayettevilleshale.aspx>.

<sup>83</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>84</sup> Data from Drillinginfo retrieved August 2014.

Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-55, which exhibits steep initial decline with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-56 illustrates theoretical EURs by county for the Fayetteville, for comparative purposes of well quality. These range from 1.02 to 2.43 billion cubic feet per well, which is somewhat higher than the 0.84 to 1.44 billion cubic feet assumed by the EIA.<sup>85</sup> The range of EURs in the top five counties is fairly small, but all are roughly double the outlying counties which will serve to limit expansion of the play in future. The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 55% and 62% of an average well's lifetime production occurs in the first four years.



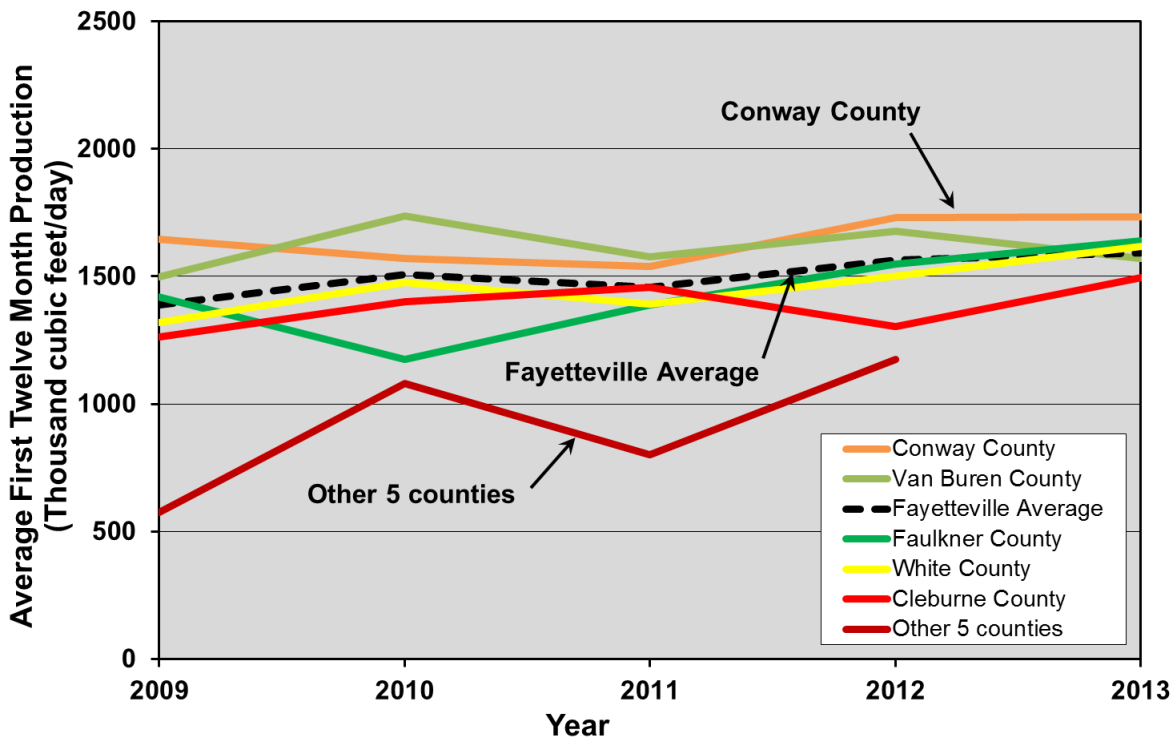
**Figure 3-56. Estimated ultimate recovery of gas per well by county for the Fayetteville play.<sup>86</sup>**

EURs are based on average well decline profiles (Figure 3-55) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life.

<sup>85</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>86</sup> Data from Drillinginfo retrieved August 2014.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the rate of production in the first year of the average well and the field decline rate, we can calculate the number of wells that need to be drilled each year to offset field decline in order to maintain production. Figure 3-57 illustrates the average first year production rate of wells by county over time. As noted earlier, average well quality for the play is up 2% in 2013 and four of the top five counties are flat to slightly rising. Van Buren County—the top producer—is declining, and no wells were drilled in 2013 outside of the top five counties, hence an estimate for that year was not possible.



© Hughes GSR Inc, 2014

(data from Drillinginfo, August, 2014)

**Figure 3-57. Average first-year gas production rates of wells by county in the Fayetteville play, 2009 to 2013.<sup>87</sup>**

Well quality is flat to slightly rising in four counties and declining in Van Buren County which is the top producer. There were no wells drilled in 2013 outside of the top five counties so no estimate was possible for that year.

<sup>87</sup> Data from Drillinginfo retrieved August 2014.

### 3.3.3.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Fayetteville play. The EIA has estimated the total play area as 2,904 square miles, including 2,132 in the “central” and 772 in the “west” area, and suggests this can be drilled at a well density of eight per square mile, for a total of 23,232 wells. In fact, the “west” area of the EIA has limited prospectivity—most wells there have ceased production—and drilling in areas outside the top five counties has ceased as of 2014. A close look at the drilling data limits the overall play area to 2,150 square miles, even allowing for 525 square miles of prospective area outside of the top five counties, for a total well count of 17,230 when the play is completely developed. As 5,297 wells have already been drilled this leaves 11,933 yet-to-drill wells.

Table 3-3 breaks down the number of yet-to-drill wells by county along with other critical parameters used for determining the future production rates of the Fayetteville play.

Parameter	County						Total
	Cleburne	Conway	Faulkner	Van Buren	White	Other 5	
Production May 2014 (Bcf/d)	0.60	0.66	0.18	0.83	0.56	0.02	2.85
% of Field Production	21.20	23.27	6.25	28.93	19.53	0.83	100.00
Cumulative Gas (Tcf)	0.72	1.14	0.33	1.61	1.20	0.07	5.08
Cumulative Liquids (MMBBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Number of Wells	904	1098	377	1547	1227	144	5297
Number of Producing Wells	848	1015	322	1441	1168	120	4914
Average EUR per well (Bcf)	1.92	2.43	1.93	2.29	2.00	1.02	2.10
Field Decline (%)	34.64	37.02	37.02	27.22	26.12	31.32	34.02
3-Year Well Decline (%)	78	78	78	79	79	80	79
Peak Year	Rising	2013	2012	2013	2011	2011	2012
% Below Peak	N/A	2	21	11	15	56	2.2
Average First Year Production in 2013 (Mcf/d)	1496	1734	1641	1571	1616	1174	1592
New Wells Needed to Offset Field Decline	140	142	40	143	90	6	610
Area in square miles	553	556	647	712	1034	3500	7002
% Prospective	70	50	30	50	40	15	31
Net square miles	387	278	194	356	414	525	2153
Well Density per square mile	2.34	3.95	1.94	4.35	2.97	0.27	2.46
Additional locations to 8/sq. Mile	2193	1126	1176	1301	2082	4056	11933
Population	25970	21273	113237	17295	77076	N/A	N/A
Total Wells 8/sq. Mile	3097	2224	1553	2848	3309	4200	17230
Total Producing Wells 8/sq. Mile	3041	2141	1498	2742	3250	4176	16847

**Table 3-3. Parameters for projecting Fayetteville production, by county.**

Area in square miles under “Other” is estimated.



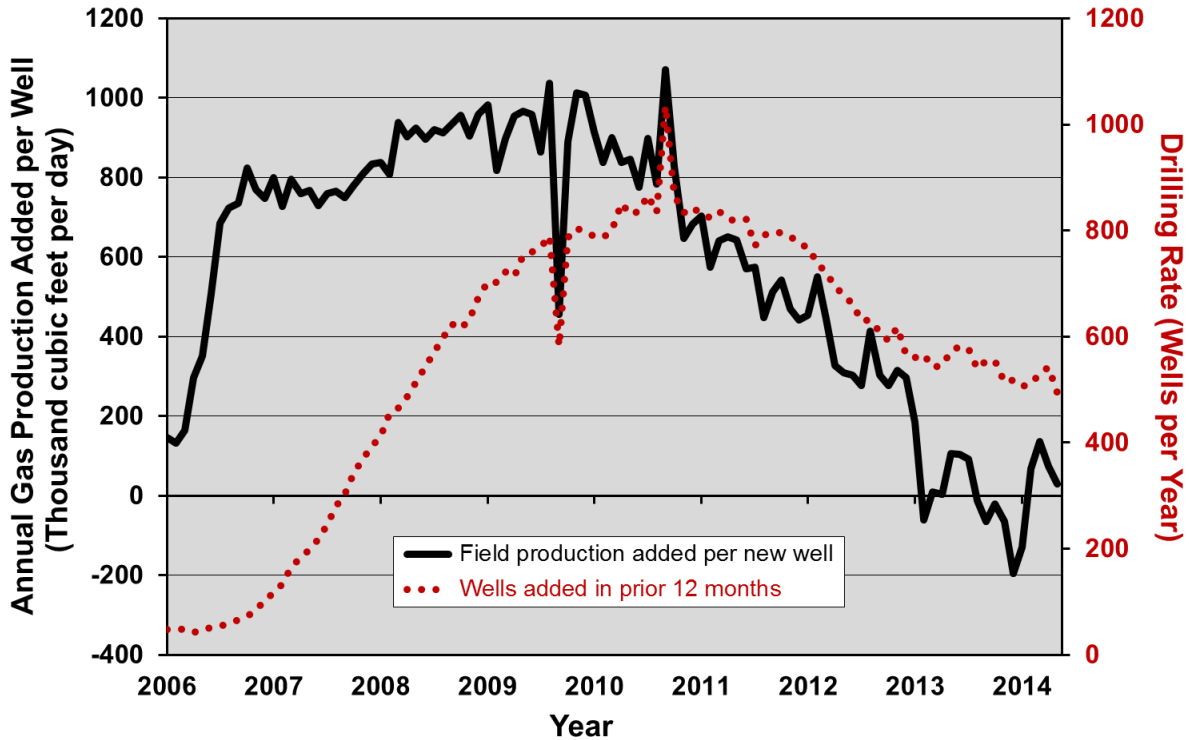
A recent in-depth study of the Fayetteville by the Bureau of Economic Geology at the University of Texas (UT) at Austin takes a more conservative view.<sup>88</sup> Although they assign a study area of 2,737 square miles, they exclude 20% of “partly drained” portions and 60% of undrilled portions from consideration, given uncertainties about surface access and prospectivity. At the time of the 2011 data cutoff used in that study, 1,252 square miles had been tested by drilling, leaving 1,485 square miles undrilled—which leaves a net developable area of 1,596 square miles. The UT study assumes in its base case that a total of 10,117 wells will be drilled by 2030, which leaves just 4,820 yet-to-drill wells by 2030 given the 5,297 wells drilled as of May 2014.

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<sup>88</sup> Browning et al., 2014, *Oil and Gas Journal*, “Study develops Fayetteville Shale reserves, production forecast,” <http://www.beg.utexas.edu/info/docs/Fayetteville%20Shale%20OGJ%20article.pdf>.

### 3.3.3.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling—the fifth key fundamental. Figure 3-58 illustrates the historical drilling rates in the Fayetteville. Drilling rates peaked in 2011 at just over 800 wells per year and have fallen to current levels of about 500 wells per year. Current drilling rates are close to the 600 wells per year required to maintain production at current levels, hence production is maintaining a slowly downward trending plateau.



**Figure 3-58. Annual gas production added per new horizontal well and annual drilling rate in the Fayetteville play, 2006 through 2014.<sup>89</sup>**

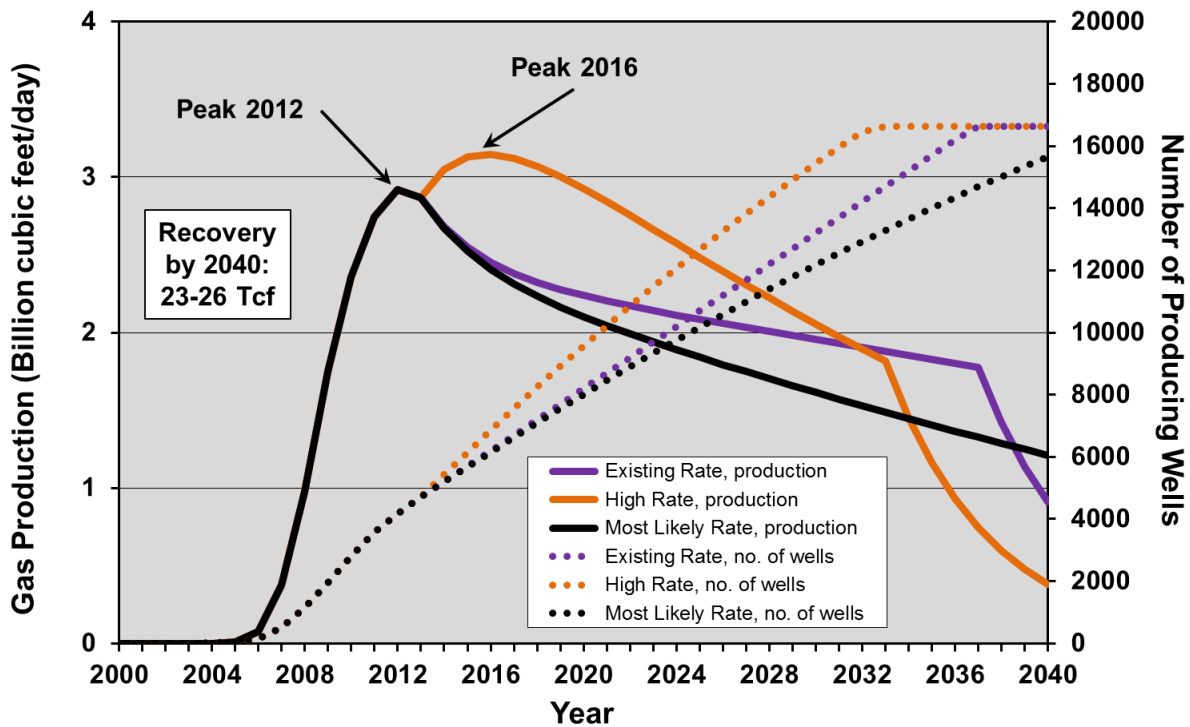
Drilling rate peaked in 2010 and is now slightly below the level needed to keep production flat.

<sup>89</sup> Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

### 3.3.3.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Fayetteville play were developed to illustrate the effects of changing the rate of drilling. Figure 3-59 illustrates the production profiles of three drilling rate scenarios if 100% of the prospective play area is drillable at eight wells per square mile. These scenarios are:

1. MOST LIKELY RATE scenario: Drilling remains at the current rate of 500 wells per year, then gradually declines to 300 wells per year.
2. EXISTING RATE scenario: Drilling remains constant at the current rate of 500 wells per year.
3. HIGH RATE scenario: Drilling increases to 750 wells per year, then gradually declines to 500 wells per year.



**Figure 3-59. Three drilling rate scenarios of Fayetteville gas production (assuming 100% of the area is drillable eight wells per square mile).<sup>90</sup>**

“Most Likely Rate” scenario: drilling holds at 500 wells/year, declining to 300 wells per year.

“Existing Rate” scenario: drilling holds constant at 500 wells/year.

“High Rate” scenario: drilling increases to 750 wells/year, declining to 500 wells/year.

<sup>90</sup> Data from Drillinginfo retrieved August 2014.

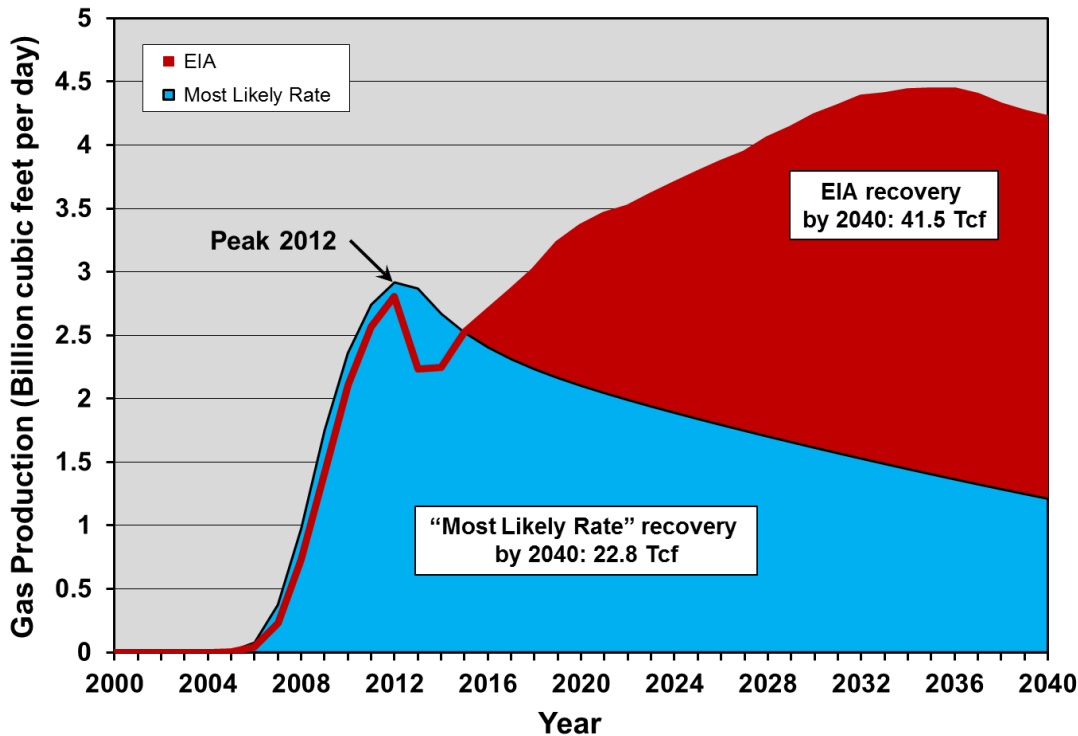
The drilling rate scenarios have the following results:

1. **MOST LIKELY RATE** scenario: The rate of drilling declines as the inventory of drilling locations is used up and drilling moves into outlying areas. Total gas recovery by 2040 would be 22.8 trillion cubic feet and drilling would continue beyond 2040.
2. **HIGH RATE** scenario: The rate of drilling increases by 50% immediately and production would increase to a new peak in 2016.. This scenario is considered unlikely unless there is a marked increase in gas price in the very near future. Total gas recovery by 2040 would be 26 trillion cubic feet and drilling would end in 2033.
3. **EXISTING RATE** scenario: Drilling continues at 500 wells per year until locations run out; this scenario is also considered unlikely given the decline in well quality in later years as drilling moves into lower productivity counties. Total gas recovery by 2040 would be 24.9 trillion cubic feet and drilling would end in 2037.

Total recovery of 22.8 trillion cubic feet by 2040 in the "Most Likely Rate" scenario is more than four times what has been recovered so far in the Fayetteville. In the "High Rate" scenario as much as 26 trillion cubic feet could be recovered; however, production rates would be far below those projected by the EIA for the Fayetteville play.

### 3.3.3.7 Comparison to EIA Forecast

Figure 3-60 illustrates the EIA’s projection for Fayetteville production through 2040 compared to the “Most Likely Rate” scenario. The EIA projects a recovery by 2040 of 41.5 Tcf to meet its reference case forecast, and projects a new peak of the play in 2036 at a level far higher than the late-2012 peak. This represents the recovery of 98% of proved reserves<sup>91</sup> and unproved resources.<sup>92</sup> Furthermore, the EIA projects that production in 2040 will be much higher than the 2012 peak, suggesting that vastly more gas will be recovered beyond 2040. This strains credibility to the limit. How can all the proved and unproved resources and reserves be extracted and still have production near all-time highs in 2040?



**Figure 3-60. “Most Likely Rate” scenario of Fayetteville gas production compared to the EIA reference case, 2000 to 2040.<sup>93</sup>**

The EIA assumes the Fayetteville will reach a new all-time high by 2036, produce 98% of proved reserves and unproved resources by 2040, and presumably produce a great deal more gas in the post-2040 period. The EIA forecast is made on a “dry gas” basis, whereas the “Most Likely Rate” scenario forecast is made on a “raw gas” basis.

<sup>91</sup> EIA, 2014, “Principal shale gas plays: natural gas production and proved reserves, 2011-12,”

[http://www.eia.gov/naturalgas/crudeoilreserves/excel/table\\_4.xls](http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls).

<sup>92</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>93</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

### 3.3.3.8 Fayetteville Play Analysis Summary

Several things are clear from this analysis:

1. Drilling rates have fallen somewhat in the Fayetteville due to gas prices, but are still remarkably high likely due to the relatively low cost of wells compared to other plays.
2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. The Fayetteville field decline rate of 34% is in the lower range for shale gas plays. Current drilling rates of 500 wells per year are slightly below the level required to maintain current production levels. Maintaining production at current levels would require the investment of \$1.4 billion per year for drilling (assuming \$2.4 million per well). Future production profiles are most dependent on drilling rate and, to a lesser extent, on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Growing production in the Fayetteville would require considerably higher gas prices to justify higher drilling rates.
3. Increasing current drilling rates by 50% could reverse the current production decline and raise production to a new peak, at 3.15 Bcf/d, in 2016, which is 10% higher than current levels. Cumulative recovery by 2040 in this high drilling rate scenario would be increased by 14% but would still be only 63% of that projected by the EIA in its reference case.
4. The projected recovery of 22.8 Tcf by 2040 in the “Most Likely Rate” scenario represents four times as much gas as has been recovered so far from the Fayetteville, and is more optimistic than the “base case” estimated ultimate recovery of 18.2 Tcf projected by the Bureau of Economic Geology at the University of Texas.<sup>94</sup> Both are significantly less than the 41.5 Tcf projected by the EIA in its reference case forecast.
5. This report’s projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained. They also assume that 100% of the prospective area is drillable. This is not a sure thing as drilling in the poorer quality parts of the play will require higher gas prices to be economic. Failure to increase current drilling rates will result in a steeper drop off in production.
6. Nearly three times the current number of wells will need to be drilled to meet the production projection of the “Most Likely Rate” scenario by 2040.
7. The EIA projection for future Fayetteville gas production included in its reference case forecast for AEO 2014,<sup>95</sup> which forecasts recovery of 98% of proved reserves plus unproved resources by 2040, strains credibility to the limit. It is highly unlikely to be realized, especially at the gas prices the EIA forecasts.<sup>96</sup>

<sup>94</sup> Browning et al., 2014, *Oil and Gas Journal*, “Study develops Fayetteville Shale reserves, production forecast,” <http://www.beg.utexas.edu/info/docs/Fayetteville%20Shale%20OGJ%20article.pdf>.

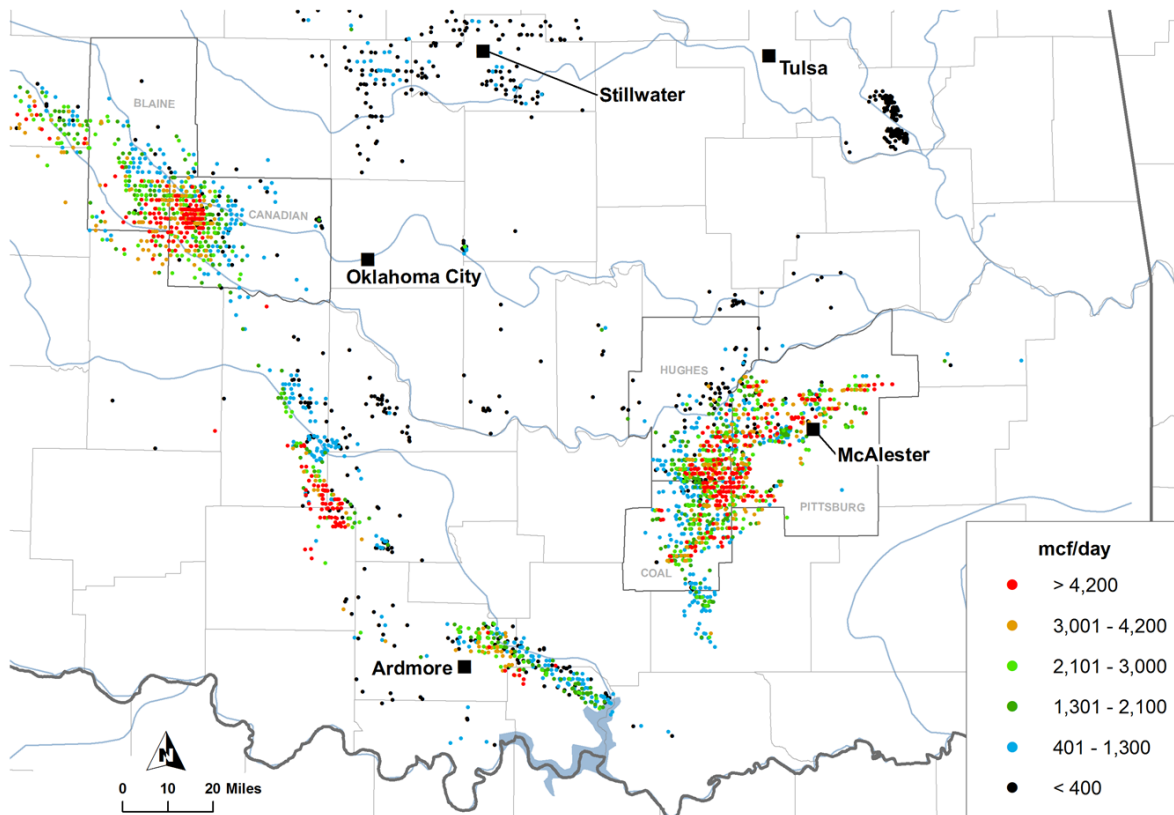
<sup>95</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>96</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo>.

### 3.3.4 Woodford Play

The EIA forecasts recovery of 23.8 Tcf of gas from the Woodford play by 2040. The analysis of actual production data presented below suggests that this forecast is somewhat—but not significantly—higher than the data suggest, although the forecast production profile is improbable.

The Woodford play in Oklahoma is primarily a shale gas play, for although parts of it are liquids rich, 92% of the energy produced from it in mid-2014 was natural gas. It is a complex play, comprising parts of the Anadarko Basin on the west, the Arkoma Basin on the east, the Chautauqua Platform in the central and northern portions, and the Oklahoma- and Ouachita-folded belts in the south and southeast. Figure 3-61 illustrates the distribution of wells as of early 2014. Since 2005 over 3,600 wells have been drilled, of which 3,062 were producing at the time of writing. The play covers parts of 31 counties although 70% of production is concentrated in five counties.

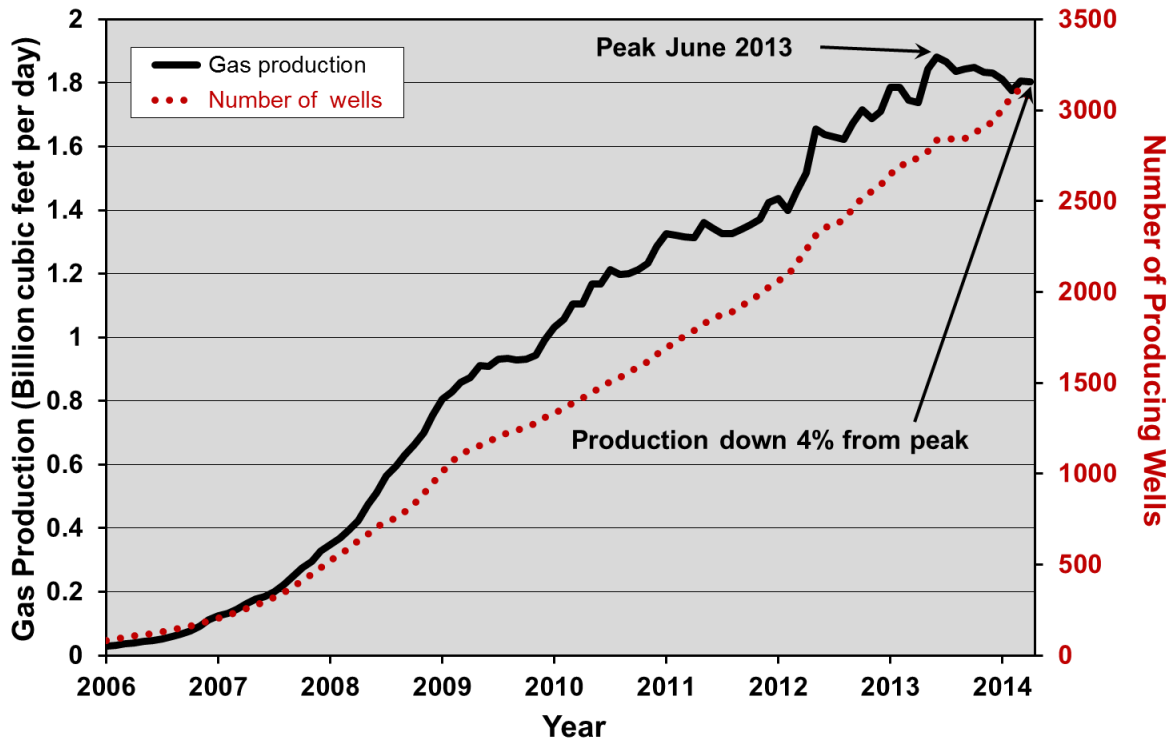


**Figure 3-61. Distribution of wells in the Woodford play as of early 2014, illustrating highest one-month gas production (initial productivity, IP).<sup>97</sup>**

Well IPs are categorized approximately by percentile; see Appendix.

<sup>97</sup> Data from Drillinginfo retrieved August 2014.

Production in the Woodford peaked at nearly 1.9 billion cubic feet per day in June 2013 as illustrated in Figure 3-62.



**Figure 3-62. Woodford play shale gas production and number of producing wells, 2006 to 2014.<sup>98</sup>**

Gas production data are provided on a “raw gas” basis.

<sup>98</sup> Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.



Although some 14% of producing wells in the Woodford are vertical/directional, 98% of current production is from horizontal fracked wells as illustrated in Figure 3-63. The rate of drilling peaked at more than 600 wells per year in 2010 but has since fallen to less than the roughly 405 wells per year required to keep production flat at current production levels. Very few vertical/directional wells are being drilled today—the future of the play lies in drilling horizontal fracked wells.

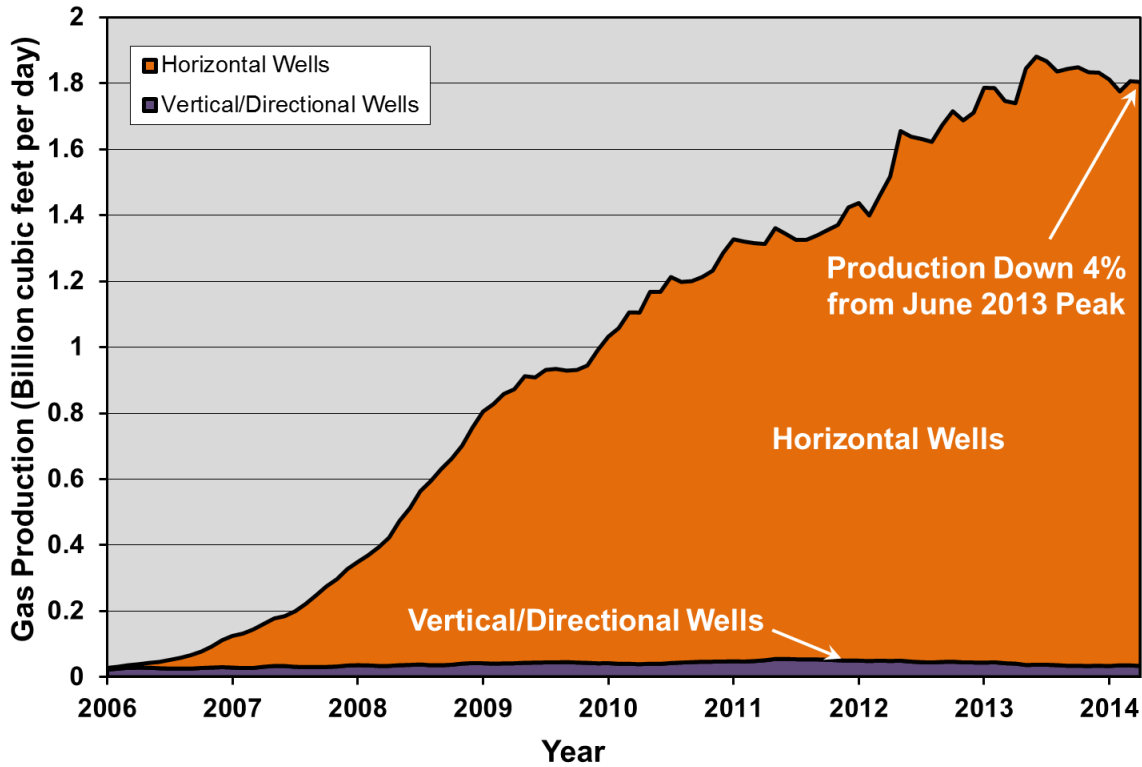
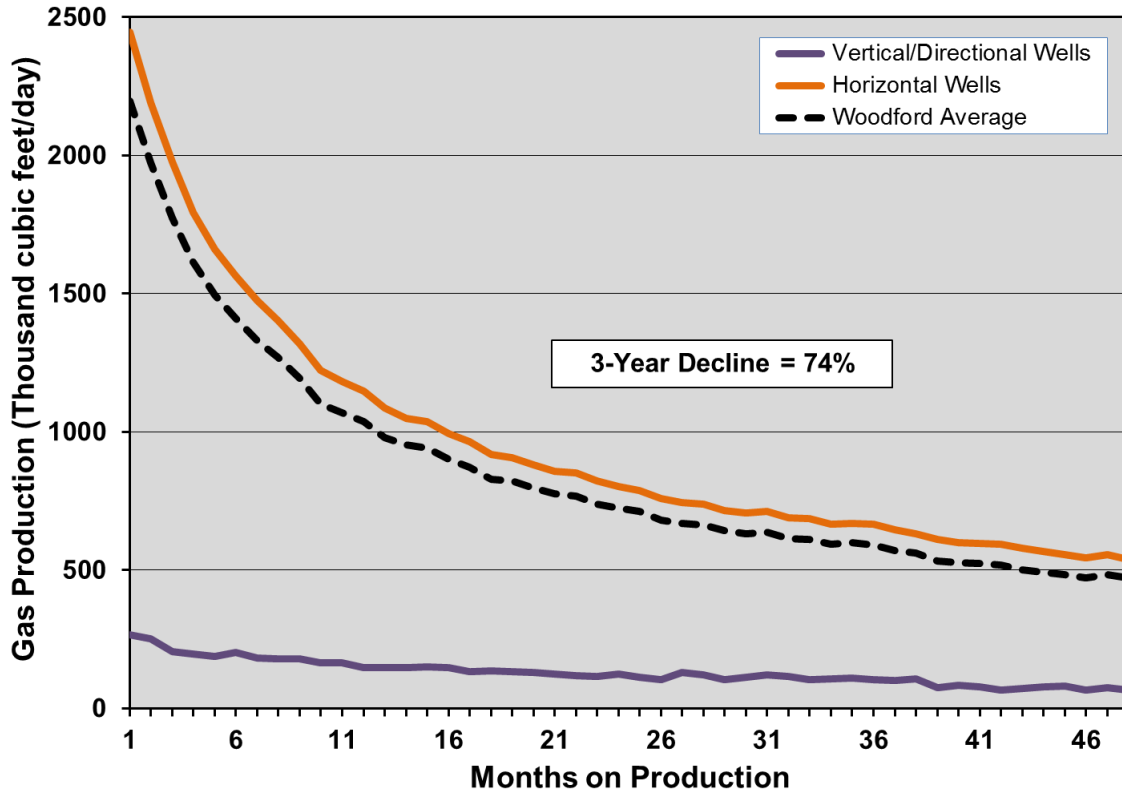


Figure 3-63. Gas production from the Woodford play by well type, 2006 to 2014.<sup>99</sup>

<sup>99</sup> Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

### 3.3.4.1 Well Decline

The first key fundamental in determining the life cycle of Woodford production is the *well decline rate*. Woodford wells exhibit high decline rates in common with all shale plays. Figure 3-64 illustrates the average decline rate of Woodford horizontal and vertical/directional wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The decline rate over the first three years of average well life is 74%, which is at the low end of typical shale plays. As can be seen, vertical/directional wells have much lower productivity than horizontal wells and hence are being phased out.



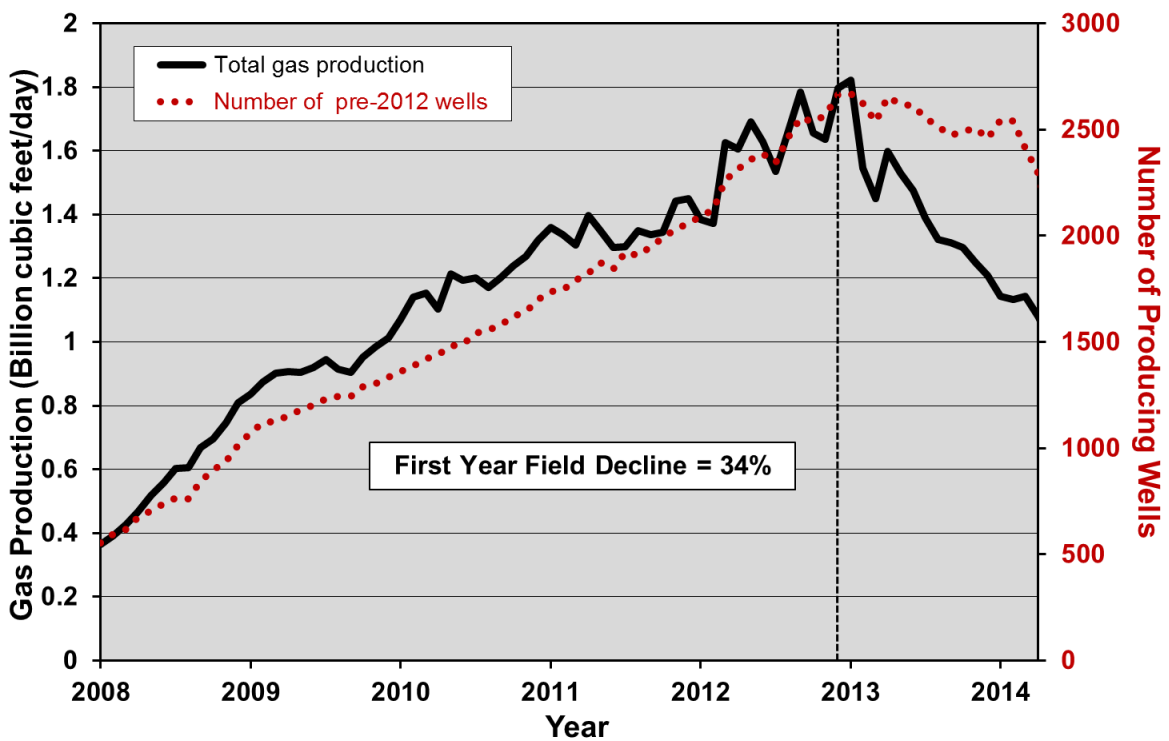
**Figure 3-64. Average decline profile for gas wells in the Woodford play.<sup>100</sup>**

Decline profile is based on all shale gas wells drilled since 2009.

<sup>100</sup> Data from Drillinginfo retrieved September 2014.

### 3.3.4.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost in the Woodford in a year without more drilling. Figure 3-65 illustrates production from the 2,600 horizontal wells drilled prior to 2013 (horizontal wells only are considered as very few vertical/directional wells are being drilled). The first-year decline rate is 34%. This is lower than the well decline rate as the field decline is made up of both new wells declining at high rates and older wells declining at lesser rates. It's also at the low end of field decline rates observed in shale plays. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, 405 new wells each year would be required to offset field decline at current production levels. At an average cost of \$9 million per well,<sup>101</sup> this would represent a capital input of about \$3.6 billion per year, exclusive of leasing and other infrastructure costs, just to keep production flat at 2013 levels.



**Figure 3-65. Production rate and number of horizontal shale gas wells drilled in the Woodford play prior to 2013, 2008 to 2014.<sup>102</sup>**

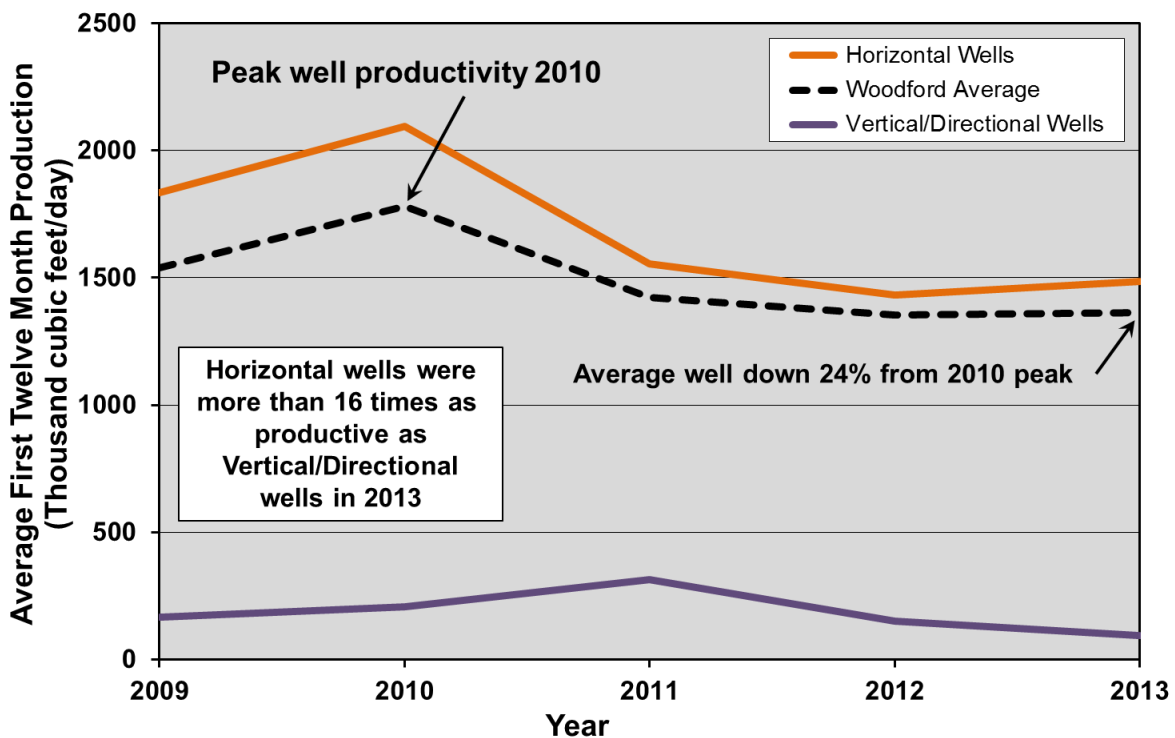
This defines the field decline for the Woodford play which is 34% per year (only production from horizontal wells is analyzed as few vertical/directional wells are likely to be drilled in the future).

<sup>101</sup> Mason, Richard, June 27, 2013, "Targeting Oklahoma's Ubiquitous Woodford Shale," [http://www.ugcenter.com/Woodford/Targeting-Oklahomas-Ubiquitous-Woodford-Shale\\_118127](http://www.ugcenter.com/Woodford/Targeting-Oklahomas-Ubiquitous-Woodford-Shale_118127).

<sup>102</sup> Data from Drillinginfo retrieved September 2014.

### 3.3.4.3 Well Quality

The third key fundamental is the *average well quality* in the Woodford by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. It is, however, approaching the limits of diminishing returns, and improvements in average well quality are non-existent in the Woodford. The average first year production rate of Woodford wells is down 24% from what it was in 2010, as illustrated in Figure 3-66. This is clear evidence that geology is winning out over technology, as drilling moves into lower-quality locations, as investigated further below, although some of the decline may be related to moves into more liquids-rich parts of the play.

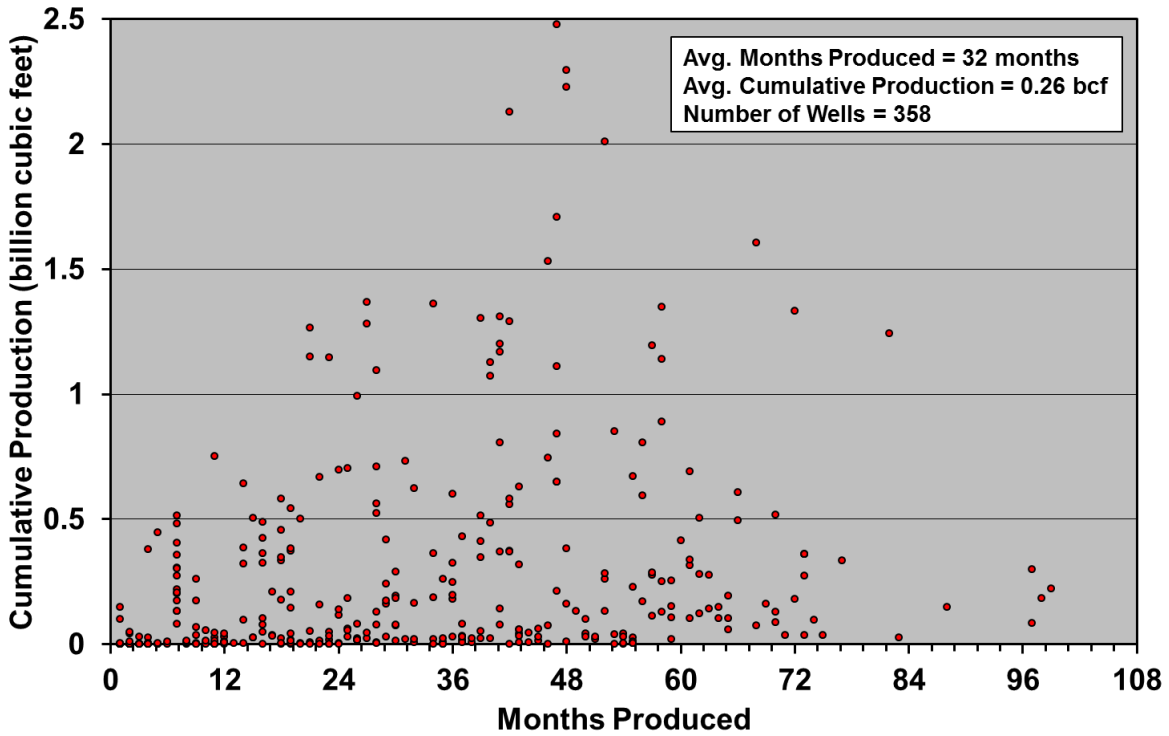


**Figure 3-66. Average first-year production rates for Woodford horizontal and vertical/directional gas wells from 2009 to 2013.<sup>103</sup>**

Average well quality has fallen by 24% from 2010, a clear indication that geology is trumping technology in this shale play.

<sup>103</sup> Data from Drillinginfo retrieved September 2014.

Another measure of well quality is cumulative production and well life. Ten percent of the wells that have been drilled in the Woodford are no longer productive. Figure 3-67 illustrates the cumulative production of these shut-down wells over their lifetime. At a mean lifetime of 32 months and a mean cumulative production of 0.26 billion cubic feet, these wells would in large part be economic losers.



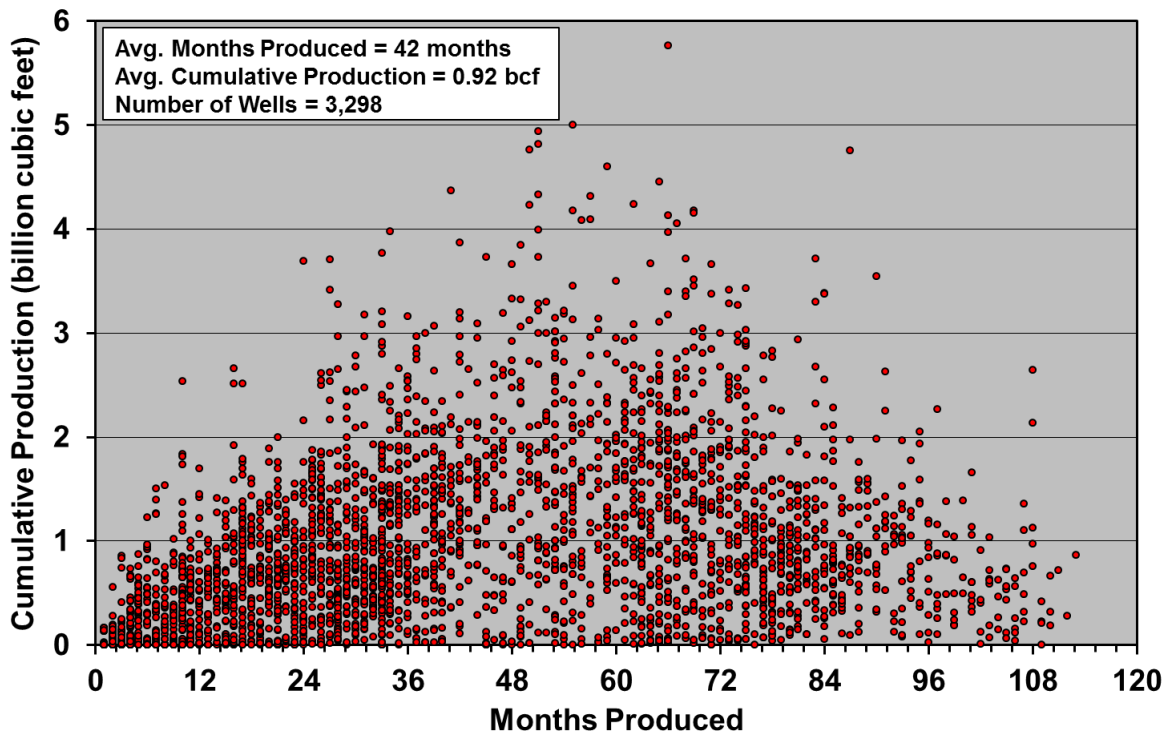
**Figure 3-67. Cumulative gas production and length of time produced for Woodford wells that were not producing as of February 2014.**

These well constitute 10% of all wells drilled; most would be economic failures, given the mean life of 32 months and average cumulative production of 0.26 billion cubic feet when production ended.<sup>104</sup>

<sup>104</sup> Data from Drillinginfo retrieved September 2014.

Figure 3-68 illustrates the cumulative production of all horizontal wells that were producing in the Woodford as of March 2014. Although it can be seen that there are a few very good wells that recovered large amounts of gas in the first few years, and undoubtedly were great economic successes, the average well had produced just 0.92 billion cubic feet over a lifespan averaging 42 months. Just 3% of these wells are more than 8 years old.

The lifespan of wells is another key parameter, as many operators assume a minimum well life of 30 years and longer, though this is conjectural given the lack of data and the significant number of wells that have been shut down after less than 8 years.

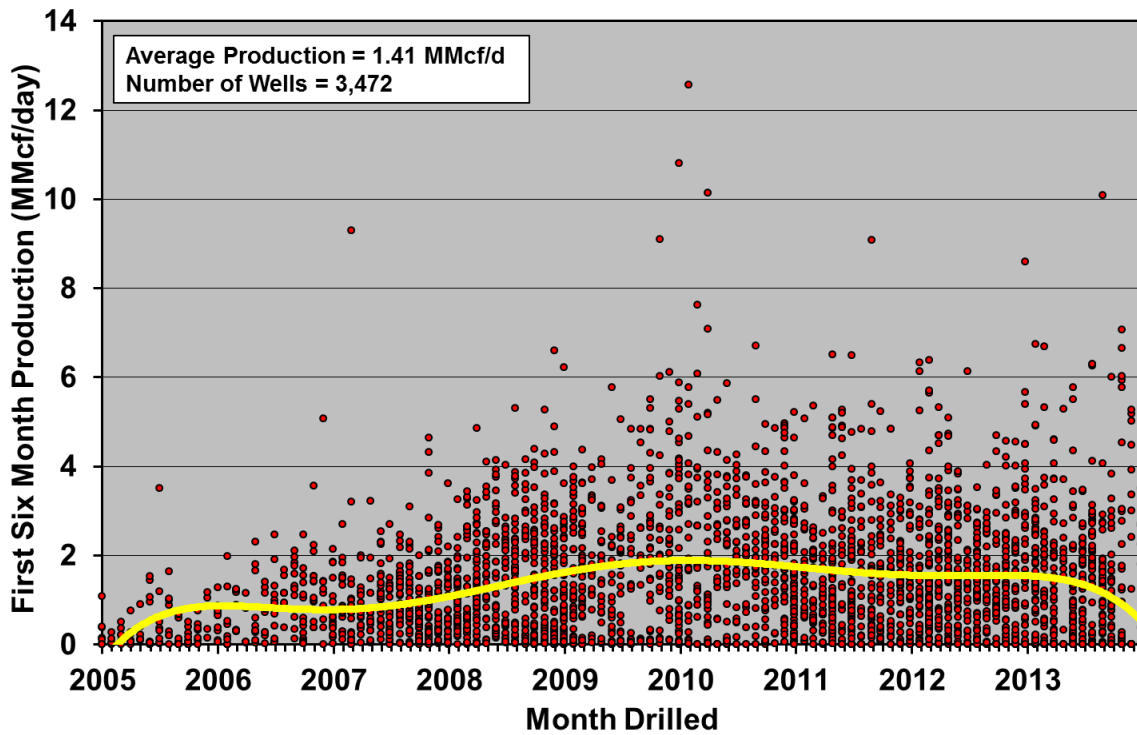


**Figure 3-68. Cumulative gas production and length of time produced for Woodford wells that were producing as of March 2014.<sup>105</sup>**

These wells constitute 90% of all wells drilled. Very few wells are greater than eight years old, with a mean age of 42 months and a mean cumulative recovery of 0.92 billion cubic feet.

<sup>105</sup> Data from Drillinginfo retrieved September 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells in not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP). Figure 3-69 illustrates the average daily output over the first six months of production for all wells in the Woodford play (six-month IP). Again, as with cumulative production, there are a few exceptional wells—5% produced more than 4 million cubic feet per day (MMcf/d)—but the average for all wells drilled since 2005 is just 1.41 MMcf/d. Figure 3-61 illustrates the distribution of IPs in map form.

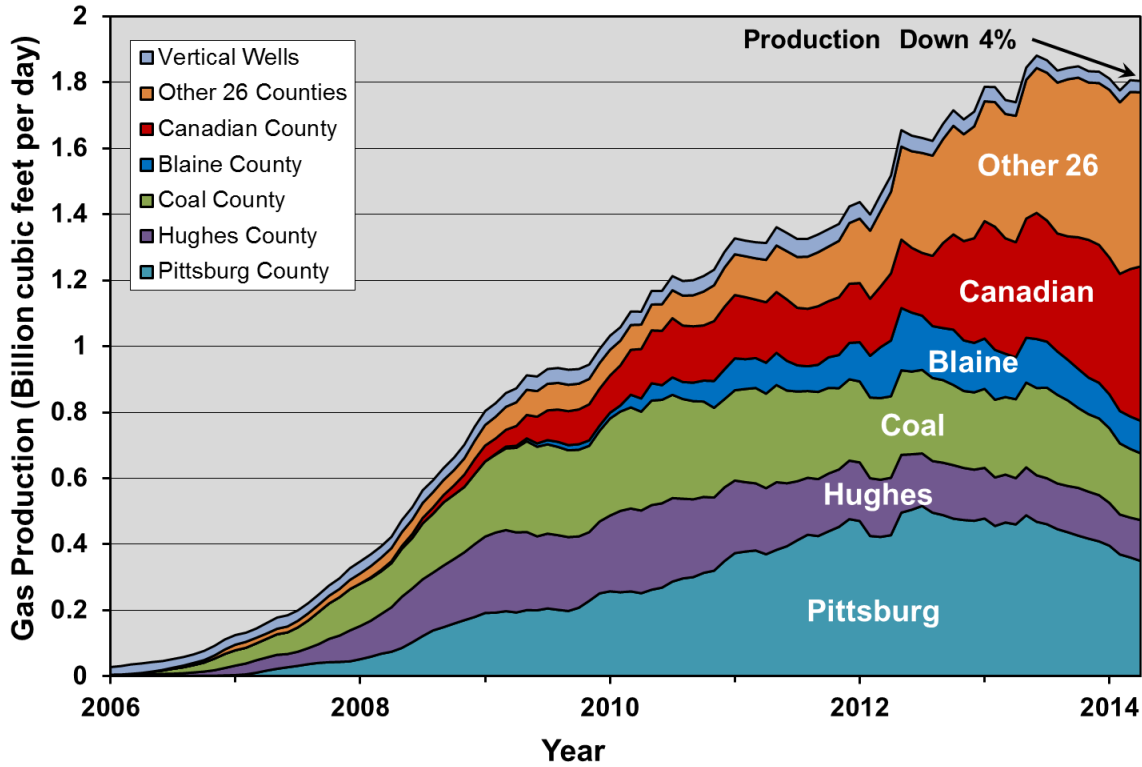


**Figure 3-69. Average gas production over the first six months for all wells drilled in the Woodford play, 2005 to 2014.<sup>106</sup>**

Although there are a few exceptional wells, the average well produced 1.41 million cubic feet per day over this period. The trend line indicates mean productivity over time.

<sup>106</sup> Data from Drillinginfo retrieved September 2014.

Different counties in the Woodford display markedly different well quality characteristics, which are critical in determining the most likely production profile in the future. Figure 3-70, which illustrates production over time by county, shows that as of April 2014, the top two counties produced 45% of the total, the top five produced 69%, and the remaining 26 counties produced 31%.

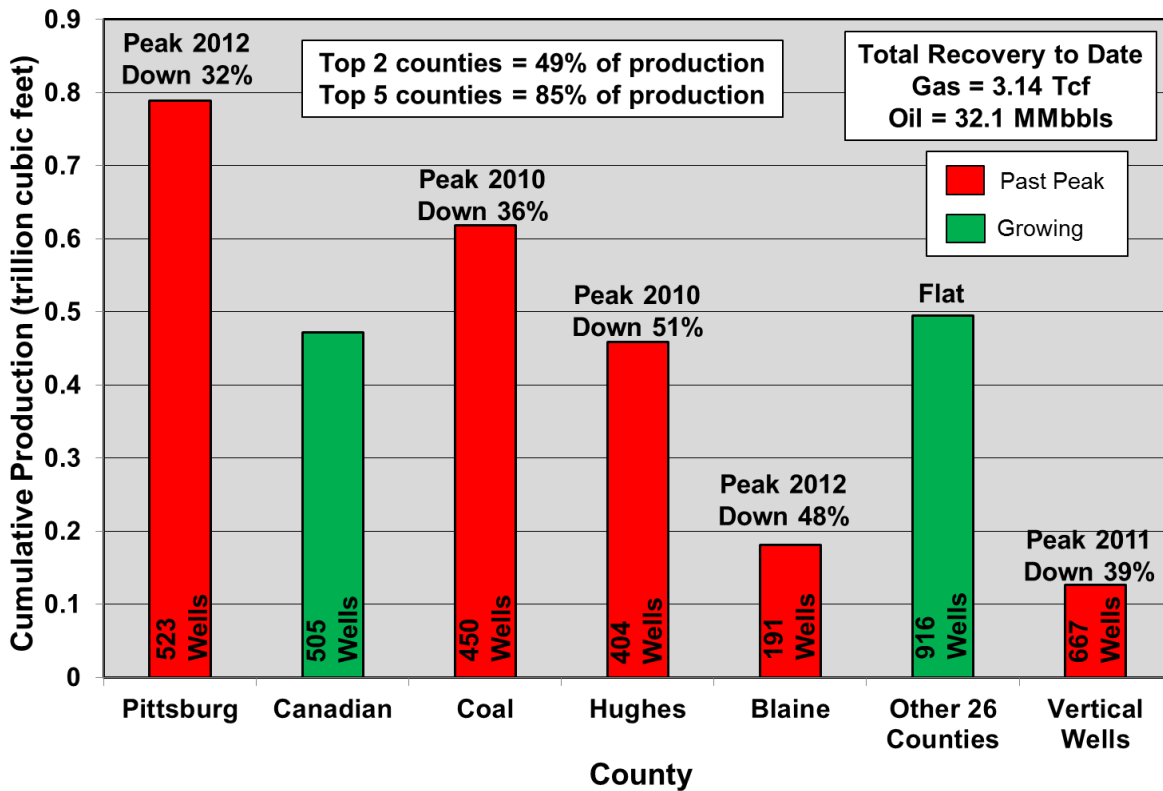


**Figure 3-70. Gas production by county in the Woodford play, 2006 through 2014.<sup>107</sup>**  
 The top five counties produced 69% of production in April 2014.

<sup>107</sup> Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.



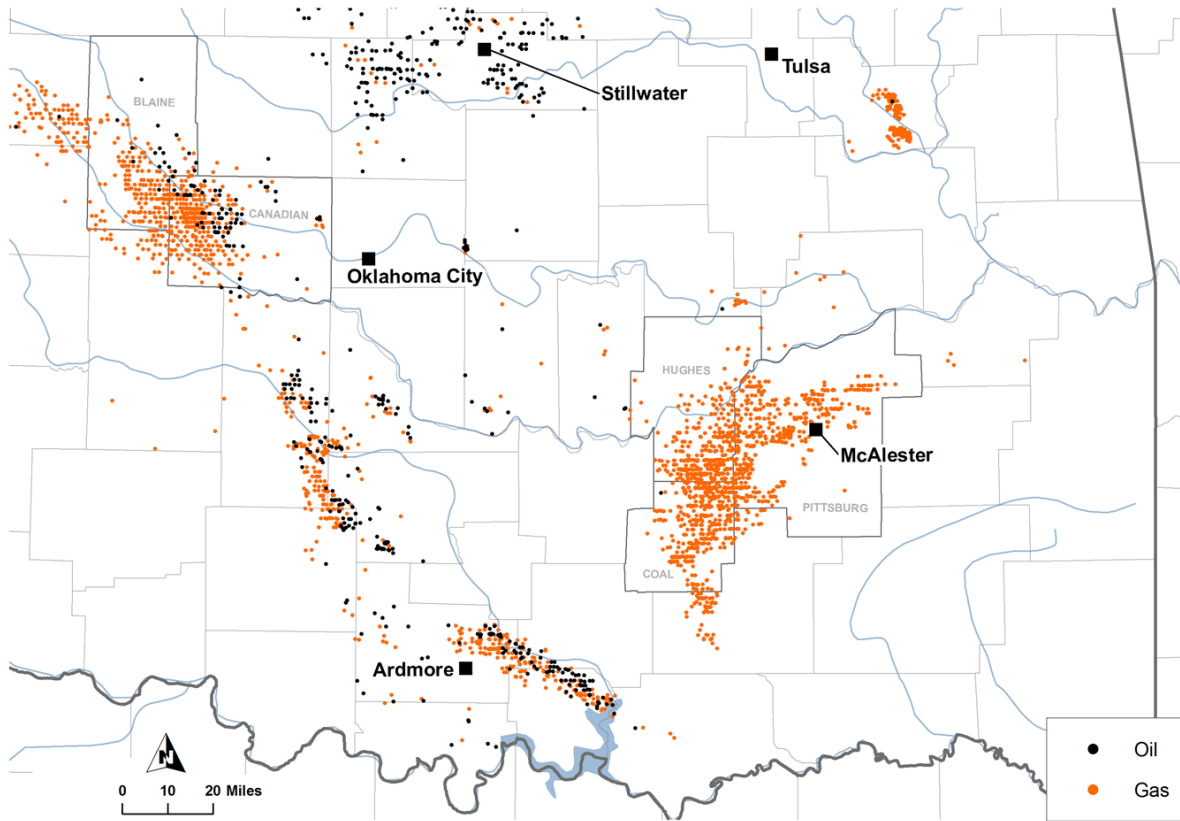
The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 3-71, the top two counties have produced 49% of the gas and the top five have produced 85%. Production in four of the top five counties peaked in 2010 to 2012 and is down sharply. Production is growing in Canadian County and is flat in the 26 counties outside the top five, which tend to be richer in liquids and are the focus of drilling in a period of low priced gas. An increase in the rate of drilling given higher gas prices could temporarily halt and perhaps reverse declines in those counties that have peaked.



**Figure 3-71. Cumulative gas production by county in the Woodford play through 2014.<sup>108</sup>**  
 The top five counties have produced 85% of the 3.14 trillion cubic feet of gas produced to date.

<sup>108</sup> Data from Drillinginfo retrieved September 2014.

The Woodford also produces limited amounts of natural gas liquids and oil. With the exception of Canadian County, most liquids production is not within the top five counties but is located in the central and northern portions, as illustrated in Figure 3-72. Some 32 million barrels of liquids have been produced since 2005, and, given low gas prices, has improved economics and driven drilling to counties where liquids can be produced.

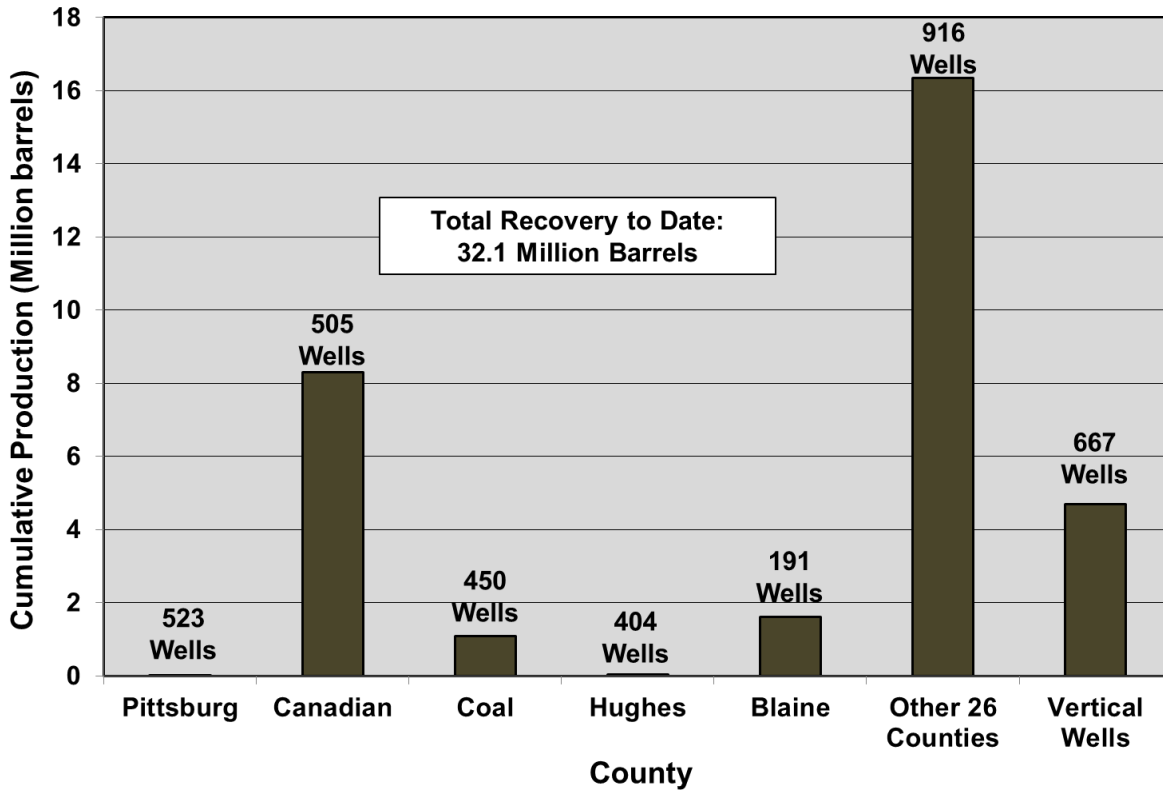


**Figure 3-72. Distribution of gas and oil wells in Woodford play as of early 2014.<sup>109</sup>**

Liquids production from wells classified as “oil” occurs mainly in the central and northern portions of the play.

<sup>109</sup> Data from Drillinginfo retrieved August 2014.

Figure 3-73 illustrates liquids production in the Woodford by county. In the big picture liquids production from the Woodford is relatively insignificant, for although it has grown significantly since 2005 it still amounted to less than 8% of the energy produced from the Woodford play in early 2014. In fact, liquids production has fallen more than 30% from a peak of 38,000 barrels per day reached in June 2013.

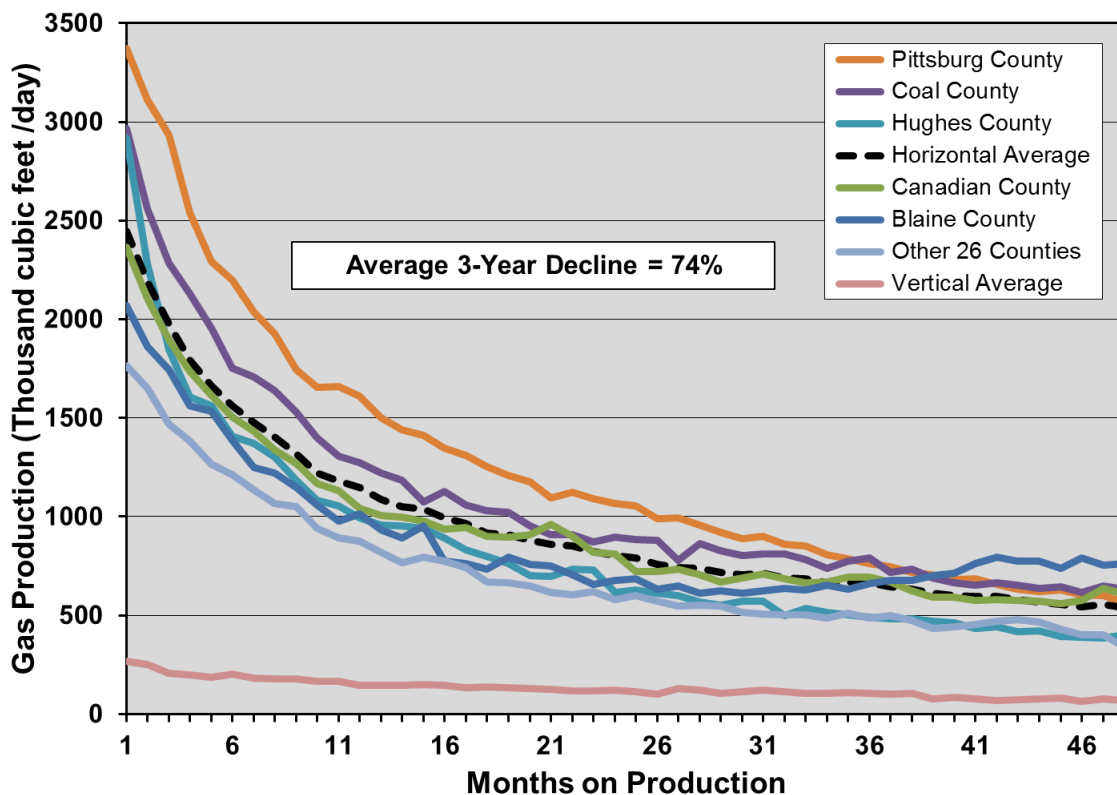


**Figure 3-73. Cumulative liquids production by county in the Woodford play through 2014.<sup>110</sup>**

Canadian and the “other 26” counties account for 77% of the 32 million barrels produced to date.

<sup>110</sup> Data from Drillinginfo retrieved September 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost on the order of \$9 million or more each, not including leasing costs and other expenses.<sup>111</sup> The areas of highest quality—the “core” or “sweet spots”—have now been well defined. Figure 3-74 illustrates average horizontal well decline curves by county which are a measure of well quality (recognizing that future gas production from the Woodford will be dominantly from horizontal, not vertical, wells). Initial well productivities (IPs) from Pittsburg, Coal and Hughes counties are significantly higher than Canadian, Blaine and the “other 26” counties, although the latter benefit from significant liquids production which improves economics. Notwithstanding the higher productivity of wells in the top counties, production has fallen between 32% and 52% from peak in four of the top five counties—a function of low gas prices, expensive wells, and available drilling locations. Halting production declines even temporarily in these counties will require significantly higher gas prices.



**Figure 3-74. Average horizontal gas well decline profiles by county for the Woodford play.<sup>112</sup>**

The top two counties, which have produced much of the gas in the Woodford, are clearly superior.

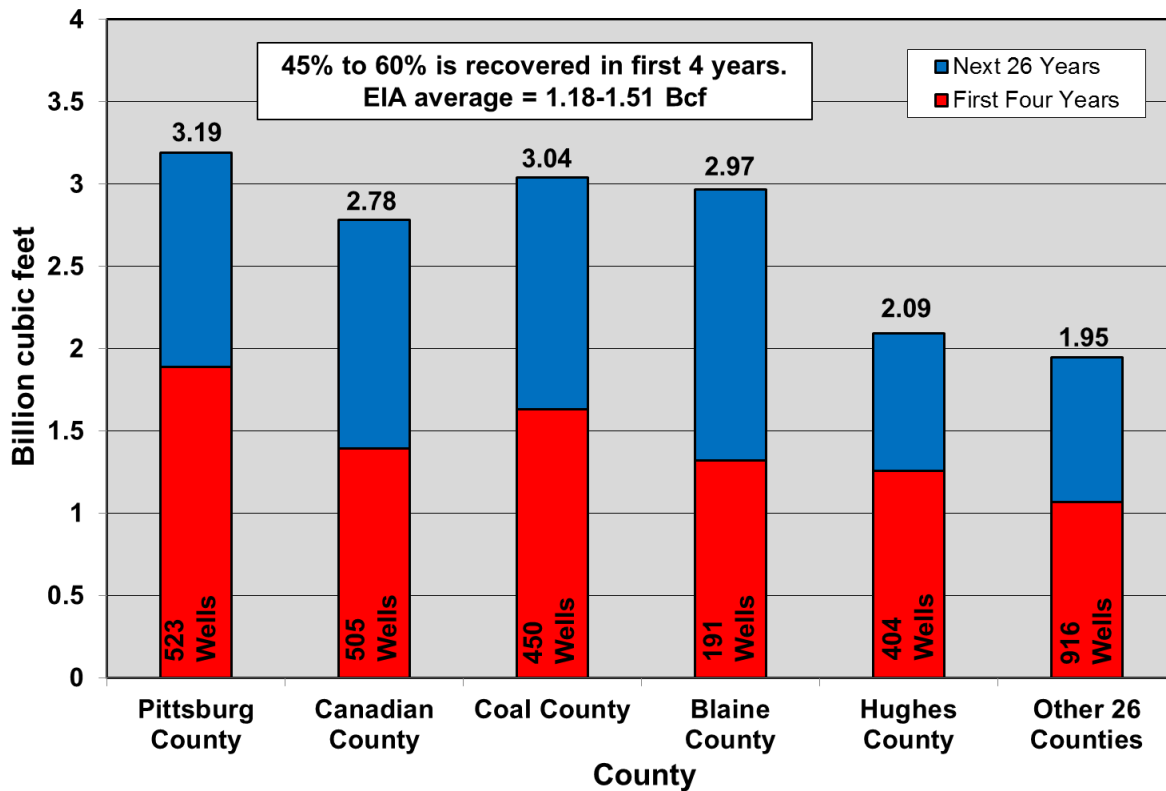
Another measure of well quality is “estimated ultimate recovery” or EUR—the amount of gas a well will recover over its lifetime. To be clear, no one knows what the lifespan of an average Woodford well is, given that few of them are more than eight years old (see Figure 3-67 and Figure 3-68), and some 10% of horizontal wells drilled have ceased production at an average age of less than three years. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-74, assuming well life spans of

<sup>111</sup> Mason, Richard, June 27, 2013, “Targeting Oklahoma’s Ubiquitous Woodford Shale,” [http://www.ugcenter.com/Woodford/Targeting-Oklahomas-Ubiquitous-Woodford-Shale\\_118127](http://www.ugcenter.com/Woodford/Targeting-Oklahomas-Ubiquitous-Woodford-Shale_118127).

<sup>112</sup> Data from Drillinginfo retrieved September 2014.

30-50 years (as is typical for conventional wells), but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Woodford. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-74, which exhibits steep initial decline with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-75 illustrates theoretical EURs by county for the Woodford for comparative purposes of well quality. These range from 1.95 to 3.19 billion cubic feet per well, which are somewhat higher than the 1.18 to 1.51 billion cubic feet assumed by the EIA.<sup>113</sup> The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 45% and 60% of an average well's lifetime production occurs in the first four years.



**Figure 3-75. Estimated ultimate recovery of gas per well by county for the Woodford play.<sup>114</sup>**

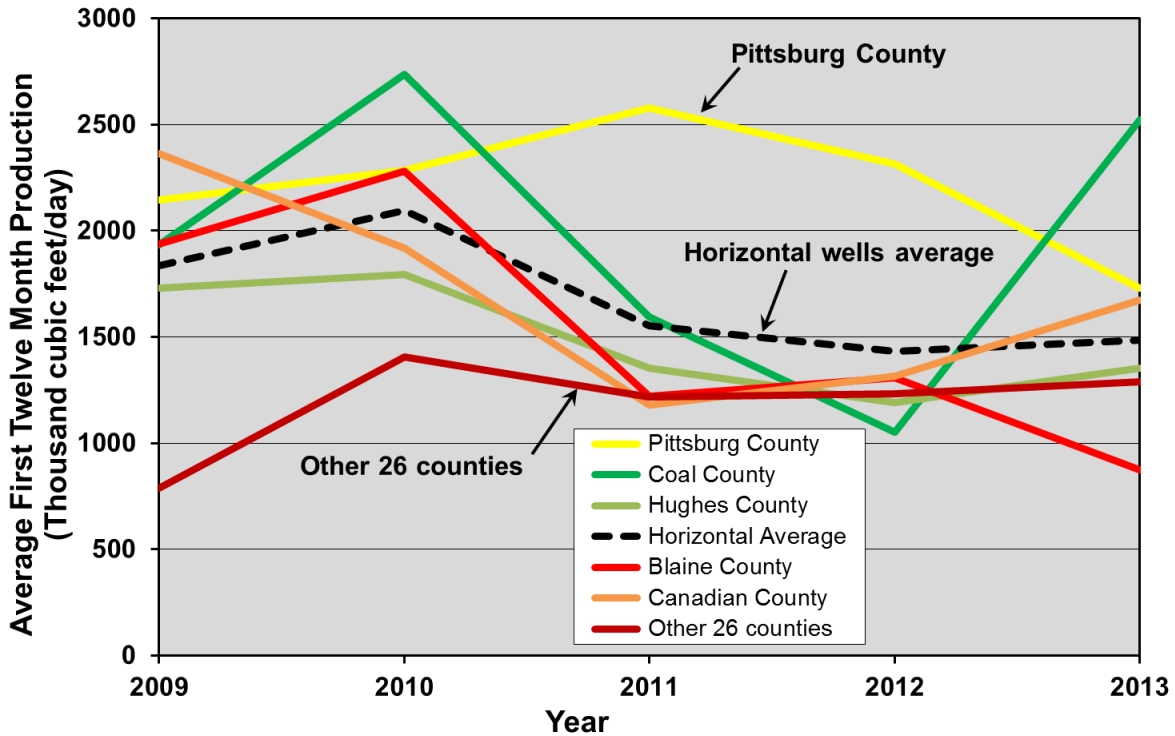
EURs are based on average well decline profiles (Figure 3-74) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the rate of production in the first year of the average well and the field decline rate, we can calculate the number of wells that need to be drilled each year to offset field decline in order to maintain production. Figure 3-76 illustrates the average first-year production rate of wells in the Woodford by county. With the

<sup>113</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>114</sup> Data from Drillinginfo retrieved September 2014.

exception of Pittsburg County, which had its peak rate in 2011, all counties experienced peak rates in 2010 and on average the play is down 24% since then. In the past two years average productivity has been flat, including significant improvement in Coal County and continued decline in Blaine and Pittsburg counties. This reflects both a lack of improvement from better technology as well as a move into liquids rich-parts of the play which in general have somewhat lower gas productivities.



**Figure 3-76. Average first-year gas production rates of wells by county for the Woodford play, 2009 to 2013.<sup>115</sup>**

Well quality is down 24% on average from 2010, notwithstanding a recent increase in Coal County.

<sup>115</sup> Data from Drillinginfo retrieved September 2014.

### 3.3.4.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Woodford play. A careful review of the top five counties suggests a prospective area of 2,358 square miles within them. The EIA has estimated the total play area at 4,246 square miles,<sup>116</sup> which leaves 1,888 prospective square miles outside the top five counties. This appears to be overly optimistic, given the distribution of production outlined in Figure 3-61, but for the sake of argument is assumed to be correct. The EIA further assumes that between 4 and 8 wells can be drilled per square mile, for an average well density of 4.6 wells per square mile.<sup>117</sup> The existing well density over this area is 0.84 wells per square mile (including vertical wells), and 0.7 including only horizontal wells. Assuming that only horizontal wells will be drilled in future, and given that vertical wells are already at a density of 0.14 per square mile, a final density of 4.5 horizontal wells per square mile is assumed. Given that 3,656 wells have already been drilled, that leaves 16,118 horizontal yet-to-drill wells, for a final well count of 19,107.

Table 3-4 breaks down the number of yet-to-drill wells by county along with other critical parameters used for determining the future production rates of the Woodford play.

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<sup>116</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>117</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

Parameter	County						Total
	Blaine County	Canadian County	Coal County	Hughes County	Pittsburg County	Other 26 Counties	
Production April 2014 (Bcf/d)	0.10	0.47	0.20	0.12	0.35	0.53	1.77
% of Field Production	6	26	11	7	20	30	100
Cumulative Gas (Tcf)	0.18	0.47	0.62	0.46	0.79	0.50	3.01
Cumulative Liquids (MMbbl)	1.61	8.31	1.09	0.04	0.00	16.35	27.41
Number of Wells	191	505	450	404	523	916	2989
Number of Producing Wells	171	451	423	361	481	745	2632
Average EUR per well (Bcf)	2.09	2.78	3.04	2.97	3.19	1.95	2.64
Field Decline (%)	38.1	46.5	14.1	17.9	28.4	40.3	32.7
3-Year Well Decline (%)	63	74	79	86	83	81	78
Peak Year	2012	Rising	2010	2010	2012	Flat	2012
% Below Peak	48	N/A	36	51	32	N/A	4
Average First Year Production in 2013 (Mcf/d)	875	1673	2522	1354	1728	1290	1486
New Wells Needed to Offset Field Decline	29	170	27	19	43	170	405
Area in square miles	929	900	518	807	1306	10000	14460
% Prospective	50	60	70	50	45	19	29
Net square miles	465	540	363	404	588	1888	4246
Well Density per square mile	0.41	0.94	1.24	1.00	0.89	0.49	0.70
Additional locations to 4.5/sq. Mile	1899	1925	1182	1412	2122	7579	16118
Population	11943	115541	5925	14003	45837	N/A	N/A
Total Wells 4.5/sq. Mile	2090	2430	1632	1816	2645	8495	19107
Total Producing Wells 4.5/sq. Mile	2070	2376	1605	1773	2603	8324	18750

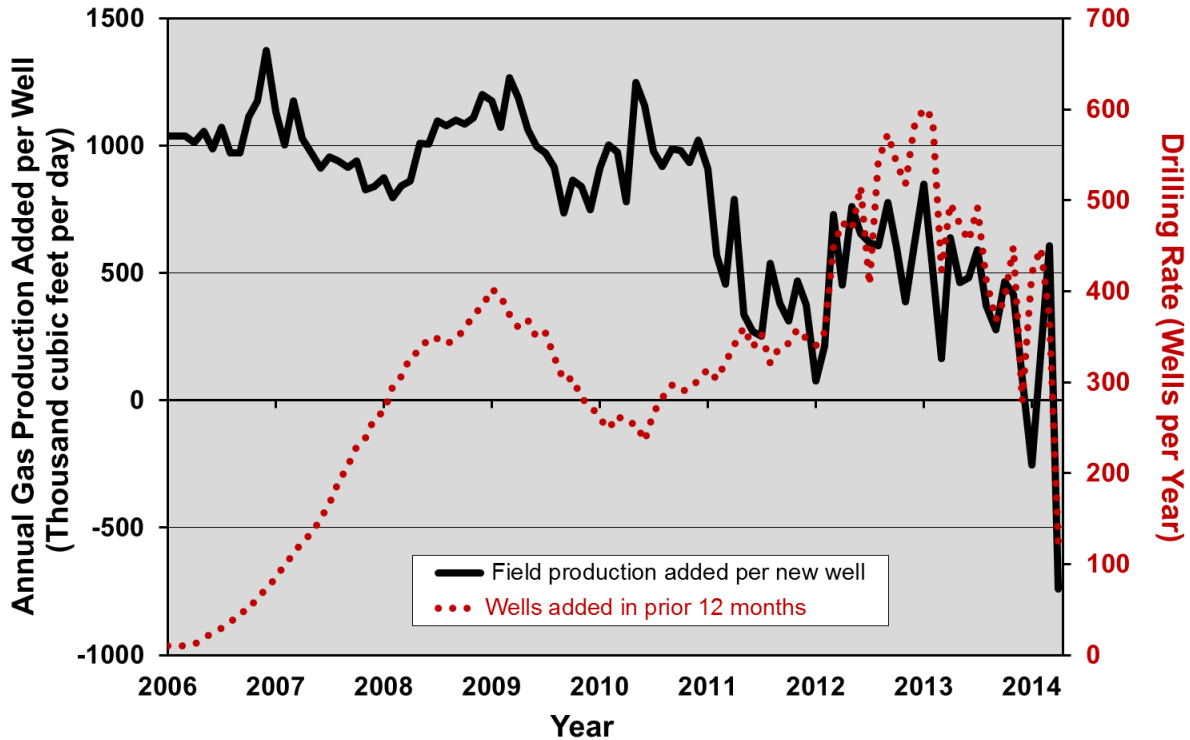
**Table 3-4. Parameters for projecting Woodford production, by county.**

Area in square miles under "Other" is estimated.



### 3.3.4.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling—the fifth key fundamental. Figure 3-77 illustrates the historical drilling rates in the Woodford. Horizontal drilling rates peaked in January 2013 at 601 wells per year and have fallen to current levels of less than 300 wells per year. Current drilling rates are somewhat less than the roughly 400 wells per year required to maintain current production, hence production is gradually declining.



**Figure 3-77. Annual production added per new horizontal well and annual drilling rate in the Woodford play, 2006 through 2014.<sup>118</sup>**

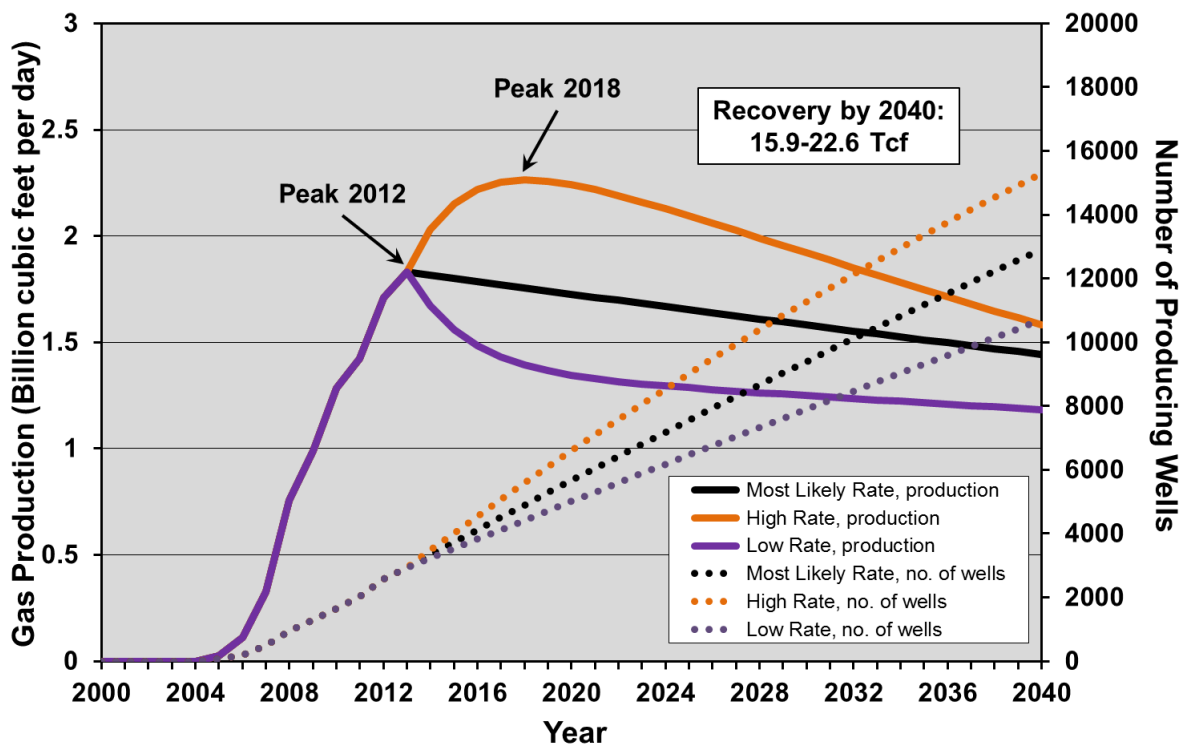
Drilling rate peaked in January 2013 and is now somewhat below the level needed to keep production flat, hence each new well now only serves to slow the overall production decline of the play.

<sup>118</sup> Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

### 3.3.4.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Woodford play were developed to illustrate the effects of changing the rate of drilling. Figure 3-78 illustrates the production profiles of three drilling rate scenarios if 100% of the prospective play area is drillable at 4.5 horizontal wells per square mile. These scenarios are:

1. MOST LIKELY RATE scenario: Drilling increases somewhat to 400 wells per year, then gradually declines to 300 wells per year.
2. LOW RATE scenario: Drilling remains at 300 wells per year, then gradually declines to 250 wells per year.
3. HIGH RATE scenario: Drilling roughly doubles to 550 wells per year, then gradually declines to 300 wells per year.



**Figure 3-78. Three drilling rate scenarios of Woodford gas production (assuming 100% of the area is drillable at 4.5 horizontal wells per square mile).<sup>119</sup>**

“Most Likely Rate” scenario: drilling increases to 400 wells/year, declining to 300 wells per year.

“Low Rate” scenario: drilling continues at 300 wells/year, declining to 250 wells/year.

“High Rate” scenario: drilling increases to 550 wells/year, declining to 300 wells/year.

The drilling rate scenarios have the following results:

1. MOST LIKELY RATE scenario: The drilling rate increases somewhat from current levels on strengthening gas prices, and then gradually declines as lower quality parts of the play are drilled.

<sup>119</sup> Data from Drillinginfo retrieved September 2014.

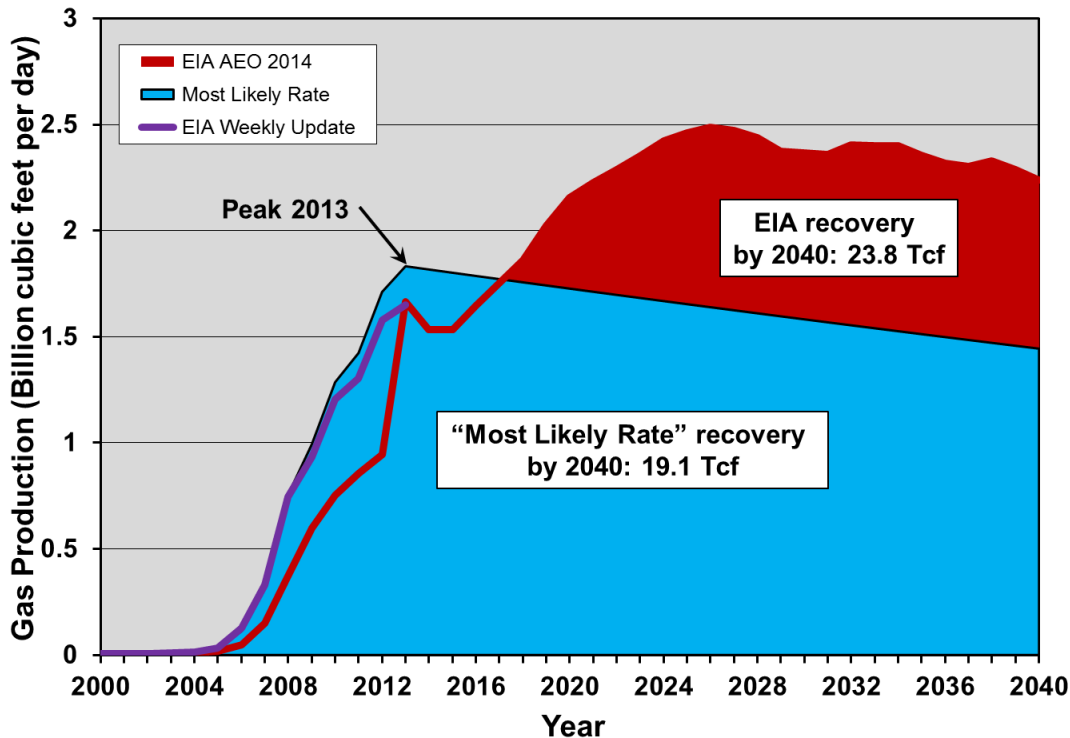
Total gas recovery by 2040 would be 19.1 trillion cubic feet and drilling would continue beyond 2040.

2. LOW RATE scenario: Drilling would continue at current rates. Total gas recovery by 2040 would be 15.9 trillion cubic feet and drilling would continue beyond 2040.
3. HIGH RATE scenario: Nearly doubling drilling rates would reverse decline and production would grow to a new peak in 2018. Total gas recovery by 2040 would be 22.6 trillion cubic feet and drilling would continue beyond 2040.

The recovery of 19.1 trillion cubic feet by 2040 in the “Most Likely” drilling rate scenario, and the recovery of 22.6 trillion cubic feet in the “High” drilling rate scenario, are somewhat less but reasonably close to the recovery of 23.8 trillion cubic feet assumed by the EIA. The “Most Likely” drilling rate scenario would see the recovery of more than six times as much gas as has been recovered to date (3.01 Tcf).

### 3.3.4.7 Comparison to EIA Forecast

Figure 3-79 illustrates the EIA's projection for Woodford production through 2040 compared to the "Most Likely Rate" scenario. Although the total recovery is not that different, the EIA has underestimated actual recovery through 2014 and assumes that production rate will ramp to a new peak in 2026 some 36% higher than the peak in 2012, and maintain production at levels considerably higher than today through 2040.<sup>120</sup> This implies the recovery of 82% of the proved reserves<sup>121</sup> and unproved resources<sup>122</sup> that the EIA assigns to the Woodford play. Although this seems highly optimistic, the EIA forecast for the Woodford is more restrained than its estimates for most other major shale plays.



**Figure 3-79. "Most Likely Rate" scenario of Woodford gas production compared to the EIA reference case, 2000 to 2040.<sup>123</sup>**

The EIA assumes the Woodford will reach a new all-time high by 2026, and maintain production at considerably higher than present levels through 2040. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis. Also shown are the EIA's Woodford gas production statistics from its *Natural Gas Weekly Update*,<sup>124</sup> which contradict the early years of its AEO 2014 forecast.

<sup>120</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>121</sup> EIA, 2014, "Principal shale gas plays: natural gas production and proved reserves, 2011-12," [http://www.eia.gov/naturalgas/crudeoilreserves/excel/table\\_4.xls](http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls).

<sup>122</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

<sup>123</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>124</sup> EIA, *Natural Gas Weekly Update*, retrieved October 2014, <http://www.eia.gov/naturalgas/weekly>.

### 3.3.4.8 Woodford Play Analysis Summary

Several things are clear from this analysis:

1. Drilling rates have fallen in the Woodford due to gas prices, and drilling has moved to liquids-rich parts of the play.
2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Current drilling rates of about 300 wells per year are somewhat below the level of about 400 wells per year required to maintain production, which would require the investment of \$3.6 billion per year for drilling (assuming \$9 million per well). Future production profiles are most dependent on drilling rate and, to a lesser extent, on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Maintaining or growing gas production in the Woodford would require considerably higher gas prices to justify higher drilling rates.
3. Doubling current drilling rates could reverse the current production decline and raise production to a new peak in the 2018 timeframe, but would increase cumulative recovery only by 19% by 2040 and wouldn't change the ultimate recovery of the play. Increasing drilling rates effectively recovers the gas sooner making the supply situation worse later.
4. The projected recovery of 19.1 Tcf by 2040 in the "Most Likely Rate" scenario, is somewhat less than the 23.8 Tcf projected by the EIA in its reference case forecast. The EIA forecast of the Woodford rising to a new production peak in 2026 at significantly higher rates than today is improbable.
5. This report's projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained. They also assume that 100% of the prospective area is drillable. This is not a sure thing as drilling in the poorer quality parts of the play will require considerably higher gas prices to be economic. Failure to maintain drilling rates will result in a steeper drop off in production.
6. More than triple the current number of wells will need to be drilled to meet the production projection of the "Most Likely Rate" scenario by 2040.
7. The EIA projection for future Woodford gas production included in its reference case forecast for AEO 2014<sup>125</sup> is highly optimistic in that it forecasts the current production decline will be reversed and rise to a new peak in 2026 at a level 36% higher than the 2012 peak of the play, and then maintain production through 2040 at levels far higher than today. This is highly unlikely to be realized, especially at the gas prices the EIA forecasts.<sup>126</sup>

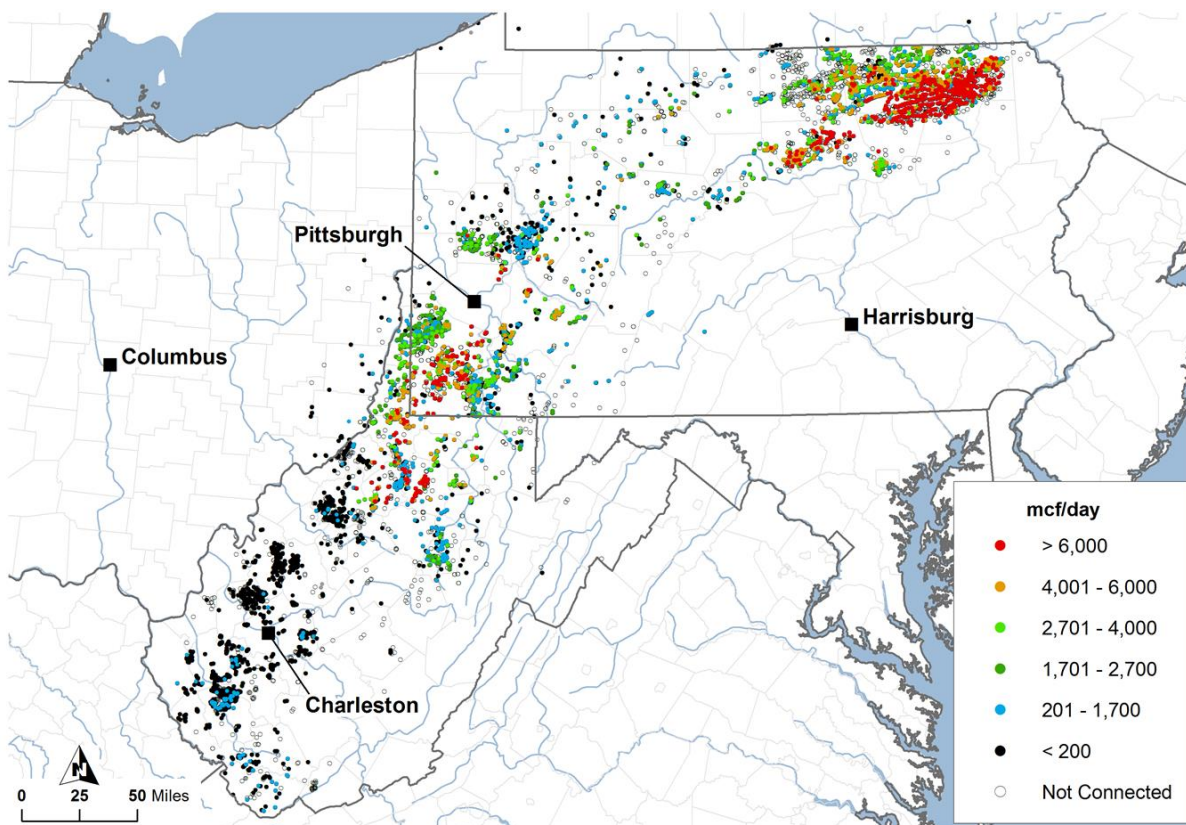
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<sup>125</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>126</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo>.

### 3.3.5 Marcellus Play

The Marcellus play is now the largest and fastest growing shale gas play in the U.S. Production growth in the Marcellus has more than compensated for declines in other plays. It is also the largest play in terms of areal extent, stretching from New York State to southern West Virginia and west to Ohio, although most production comes from Pennsylvania. Figure 3-80 illustrates the distribution of wells as of mid-2014. Over 10,700 wells have been drilled to date of which 7,006 were producing at the time of writing. Of these, more than 7,900 are in Pennsylvania, 5,302 of which were producing in mid-2014. There is a large backlog of drilled but not connected wells (also indicated in Figure 3-80), believed to be over two thousand in number. This is a function of the rate of drilling and the relative youth of the play; most of these wells will be connected over time as pipeline infrastructure catches up.

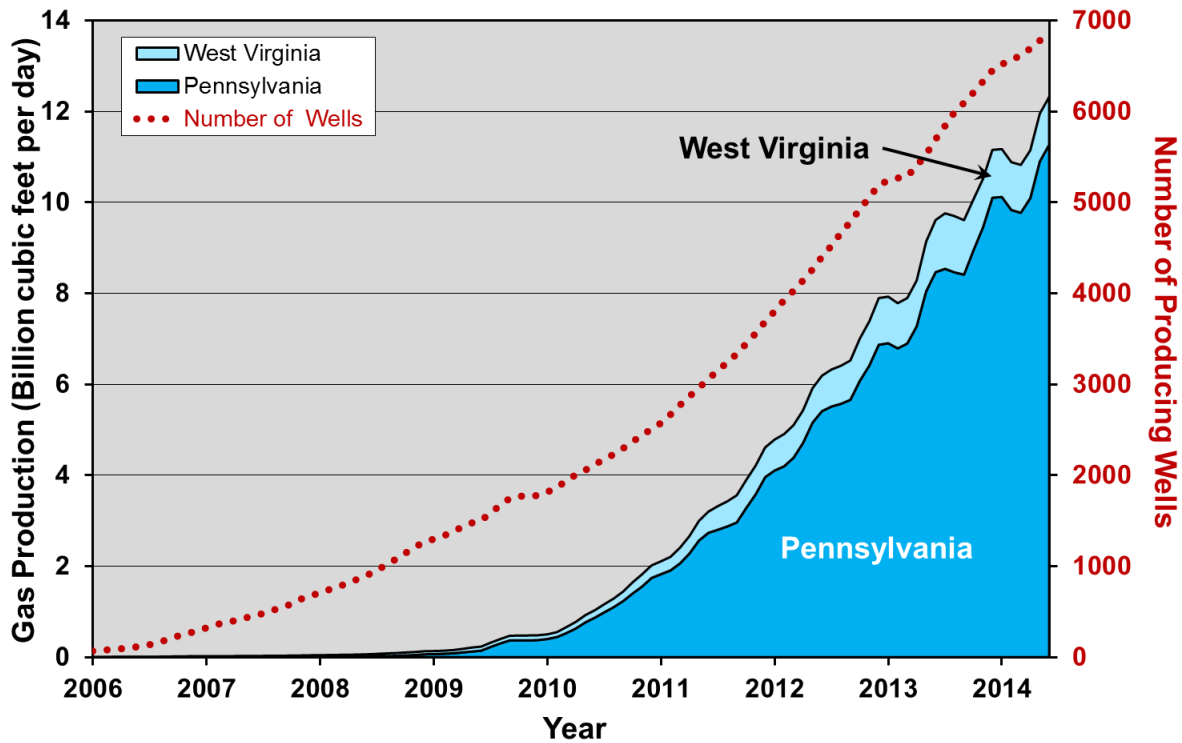


**Figure 3-80. Distribution of wells in Marcellus play as of mid-2014, illustrating highest one-month gas production (initial productivity, IP).<sup>127</sup>**

Well IPs are categorized approximately by percentile; see Appendix.

<sup>127</sup> Data from Drillinginfo retrieved September 2014.

Production from the Marcellus exceeded 12 billion cubic feet per day in June 2014 as illustrated in Figure 3-81. More than 91% of production came from Pennsylvania with most of the remainder from West Virginia. Ohio and New York State production is negligible. Over 98% of Pennsylvania production is from horizontal fracked wells, whereas 22% of production in West Virginia came from vertical/directional wells. The rate of drilling grew to a maximum of more than 1,500 wells per year in mid-2012 through 2013 and has now fallen to about 1,300 per year. Drilling rates are still well above the approximately 1,000 wells per year required to keep production flat at current production levels, so production will keep rising.

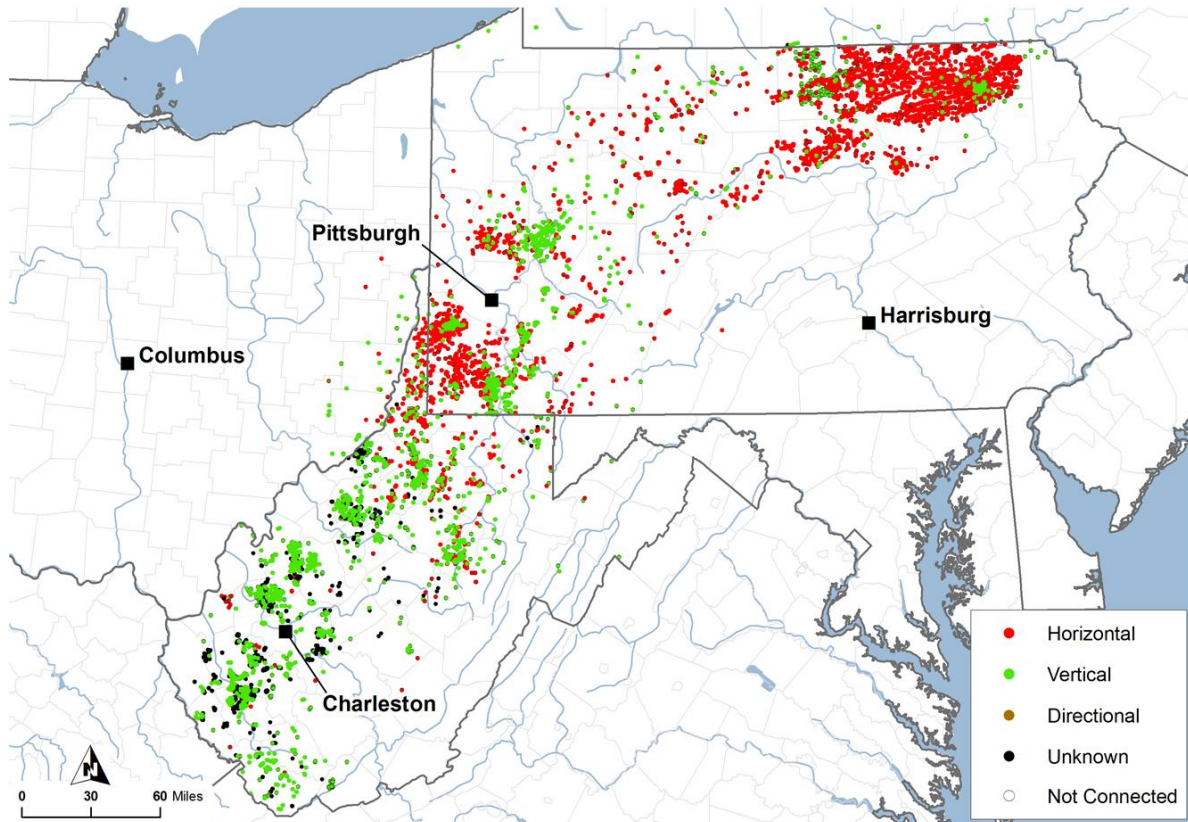


**Figure 3-81. Marcellus play shale gas production, differentiating between Pennsylvania and West Virginia, and number of producing wells, 2006 to 2014.<sup>128</sup>**

Gas production data are provided on a “raw gas” basis.

<sup>128</sup> Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

Vertical wells played a significant role in the early development of the Marcellus play in West Virginia and still produce some oil and gas, although new wells are predominantly horizontal. Although there are some legacy vertical wells in Pennsylvania, virtually all new drilling is horizontal. The distribution of horizontal and vertical/directional wells in the play is illustrated in Figure 3-82.



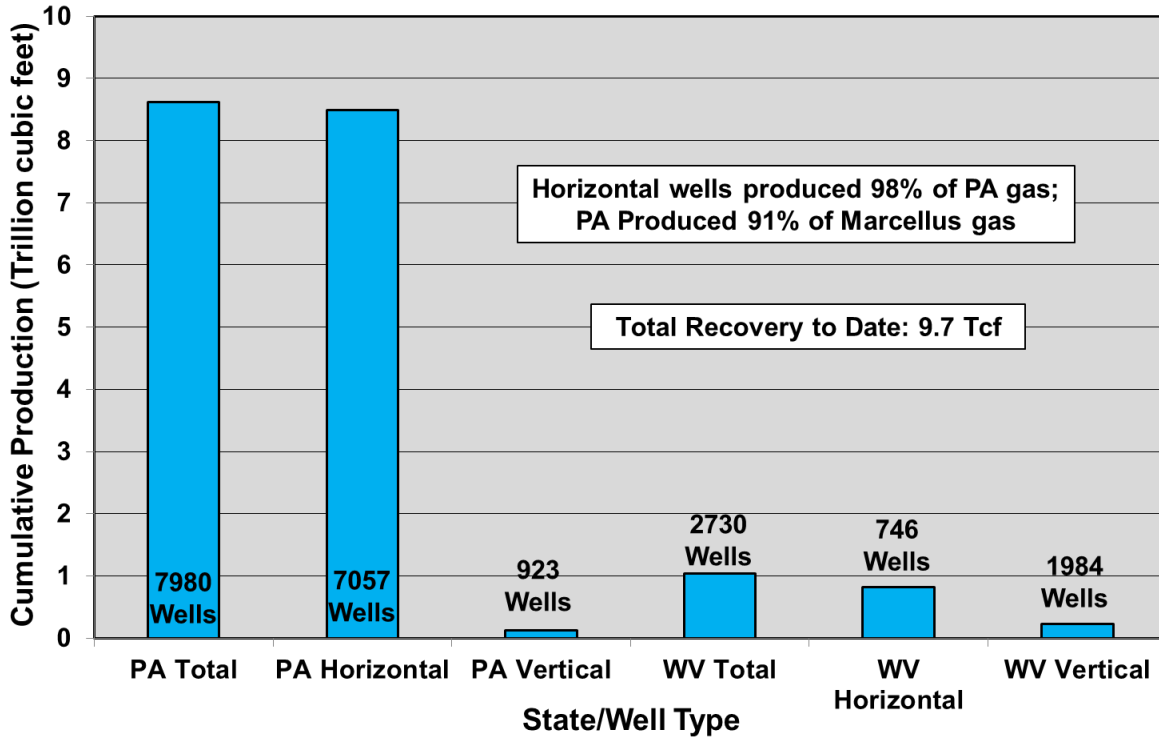
**Figure 3-82. Distribution of wells in Marcellus play categorized by drilling type as of mid-2014.<sup>129</sup>**

Development began with vertical and directional wells before expanding to largely horizontal drilling at present.

<sup>129</sup> Data from Drillinginfo retrieved September 2014.



Cumulative gas recovery by well type in Pennsylvania and West Virginia is illustrated in Figure 3-83. Although vertical/directional wells make up 23% of currently producing wells, they have produced less than 4% of the gas. There will be few if any additional vertical/directional wells drilled in the Marcellus play—future production growth will rely on horizontal fracked wells.



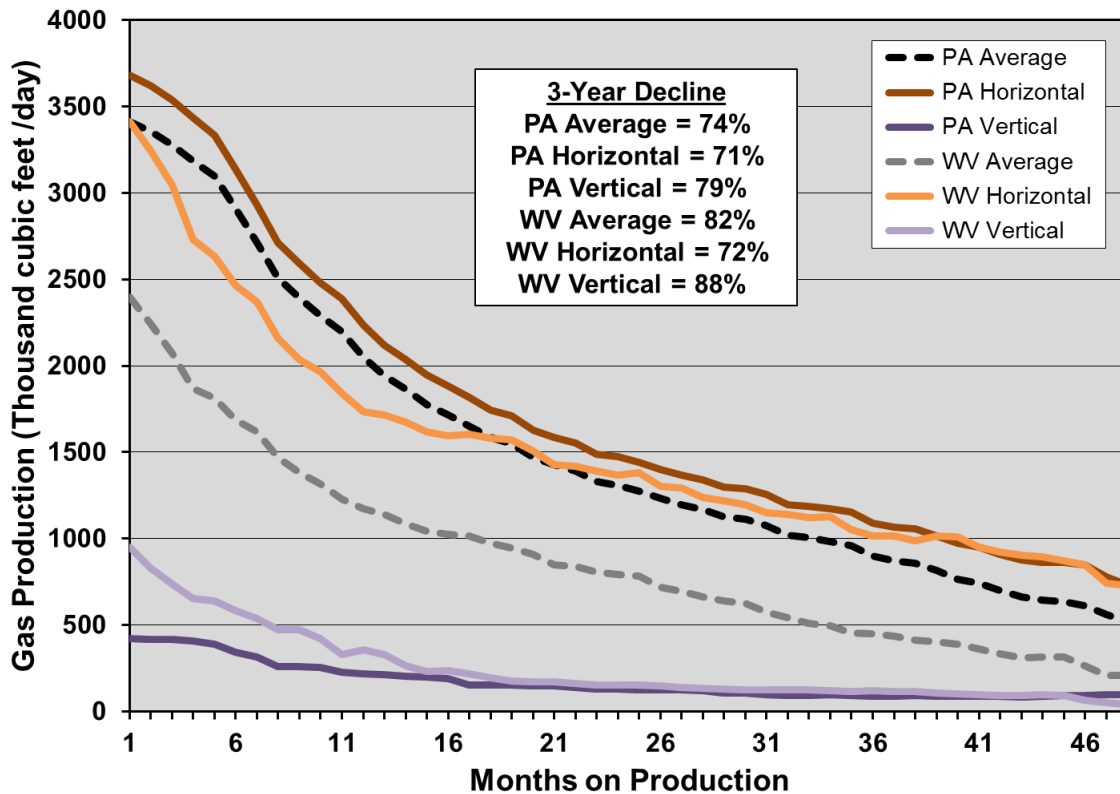
**Figure 3-83. Cumulative gas production in the Marcellus play by well type and state, 2000 to 2014.**<sup>130</sup>

The well count includes all producing wells as well as those drilled but not producing, either because they are not connected to pipelines or have ceased production.

<sup>130</sup> Data from Drillinginfo retrieved September 2014.

### 3.3.5.1 Well Decline

The first key fundamental in determining the life cycle of Marcellus production is the *well decline rate*. Marcellus wells exhibit high decline rates in common with all shale plays. Figure 3-84 illustrates the average decline rate of the most recent Marcellus horizontal and vertical/directional wells by state. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The decline rates over the first three years of average well life range between 74% and 82%, which is on the lower end of the range for most shale plays. As can be seen, vertical/directional wells have much lower productivity than horizontal wells and hence are being phased out.



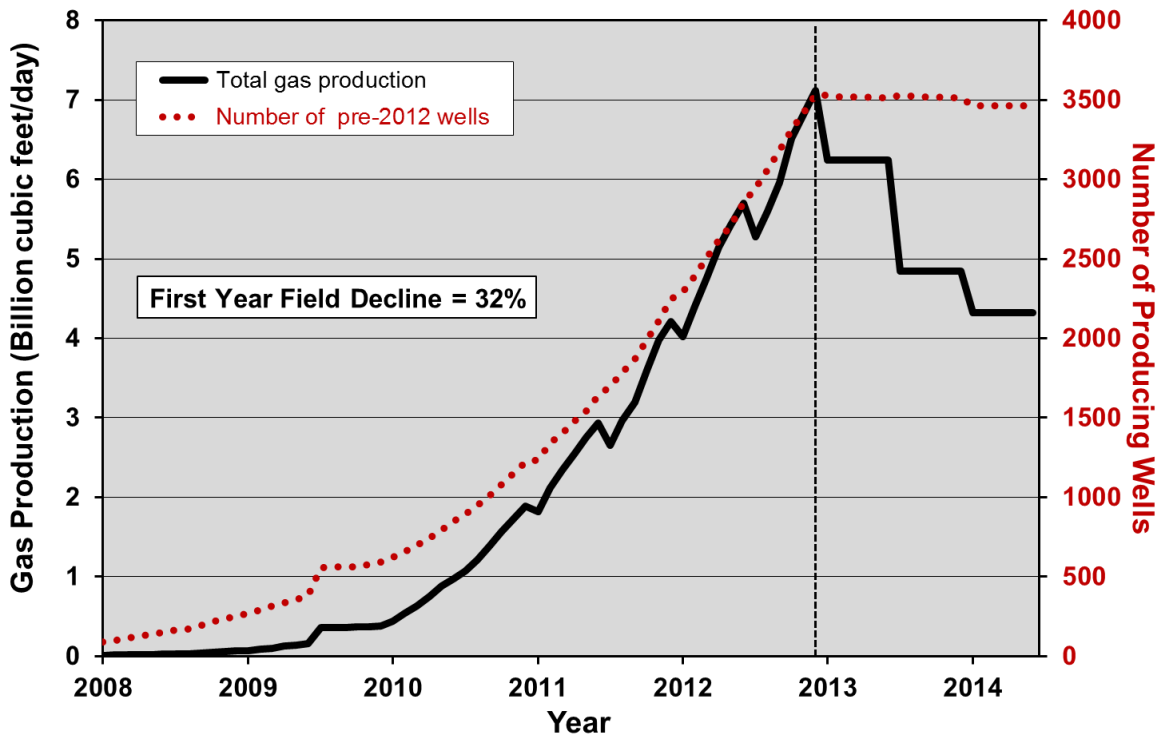
**Figure 3-84. Average decline profile for horizontal and vertical/directional gas wells in the Marcellus play, by state.<sup>131</sup>**

Decline profile is based on all shale gas wells drilled since 2009.

<sup>131</sup> Data from Drillinginfo retrieved September 2014.

### 3.3.5.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost in a year without more drilling. Figure 3-85 illustrates production from the 3,500 horizontal wells drilled prior to 2013 in Pennsylvania. The first-year decline rate is 32%, which is on the low end of field decline rates observed for shale plays. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, approximately 1,000 new wells each year would be required to offset field decline at current production levels. At an average cost of \$5 million per well, this would represent a capital input of about \$5 billion per year, exclusive of leasing and other infrastructure costs, to keep production flat at mid-2014 levels.



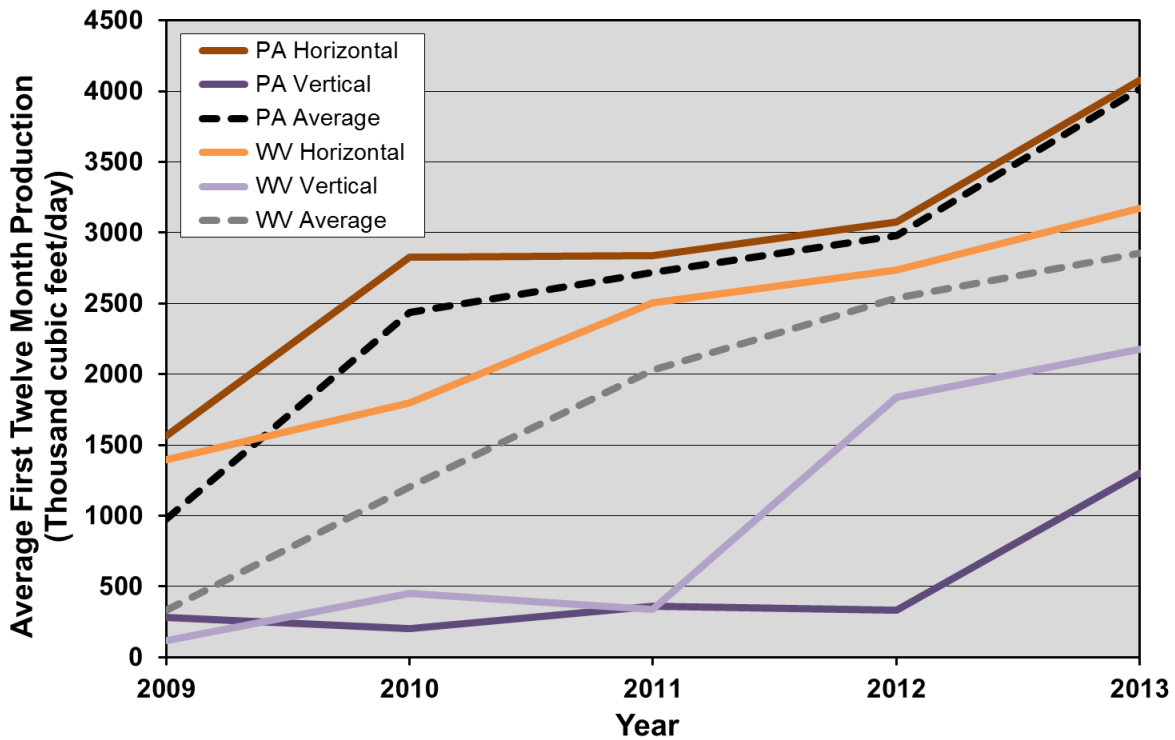
**Figure 3-85. Production rate and number of horizontal shale gas wells drilled in the Marcellus play in Pennsylvania prior to 2013, 2008 to 2014.<sup>132</sup>**

This defines the field decline for the Marcellus play which is 32% per year (horizontal wells will be responsible for virtually all future production). The stepped nature of the production curve is due to the fact that Pennsylvania releases data in six month chunks, not on a monthly basis.

<sup>132</sup> Data from Drillinginfo retrieved September 2014.

### 3.3.5.3 Well Quality

The third key fundamental is the *average well quality* by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. In the Marcellus, well quality is continuing to grow strongly, suggesting that better technology is having an effect, along with a better understanding of the reservoir and the location of sweet spots. The average first-year production rate of Marcellus wells over time is illustrated in Figure 3-86.



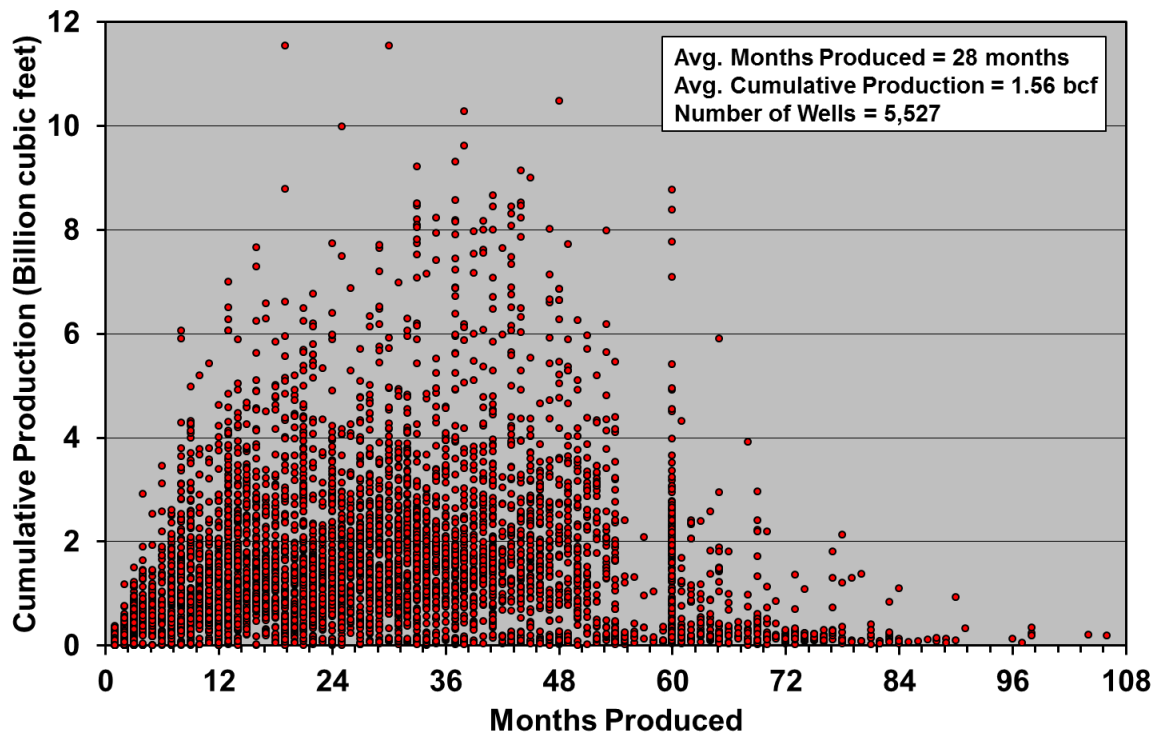
**Figure 3-86. Average first-year production rates for Marcellus horizontal and vertical/directional gas wells by state, 2009 to 2013.<sup>133</sup>**

Average well quality has increased substantially as better technology is applied and drilling is focused on the sweet spots.

<sup>133</sup> Data from Drillinginfo retrieved September 2014.

Another measure of well quality is cumulative production and well life. Figure 3-87 illustrates the cumulative production of all horizontal wells that were producing in the Pennsylvania Marcellus as of June 2014 (Pennsylvania is focused on as it has generally higher quality wells and more than 90% of Marcellus production). Although it can be seen that there are a few very good wells that recovered large amounts of gas in the first few years, and undoubtedly were great economic successes—7% of wells had recovered more than 4 billion cubic feet after less than 5 years—the average well had produced just 1.56 billion cubic feet over a lifespan averaging 28 months. Less than 6% of these wells are more than 5 years old.

The lifespan of wells is another key parameter as many operators assume a minimum life of 30 years and longer—this is conjectural at this point given the lack of long term well performance data.

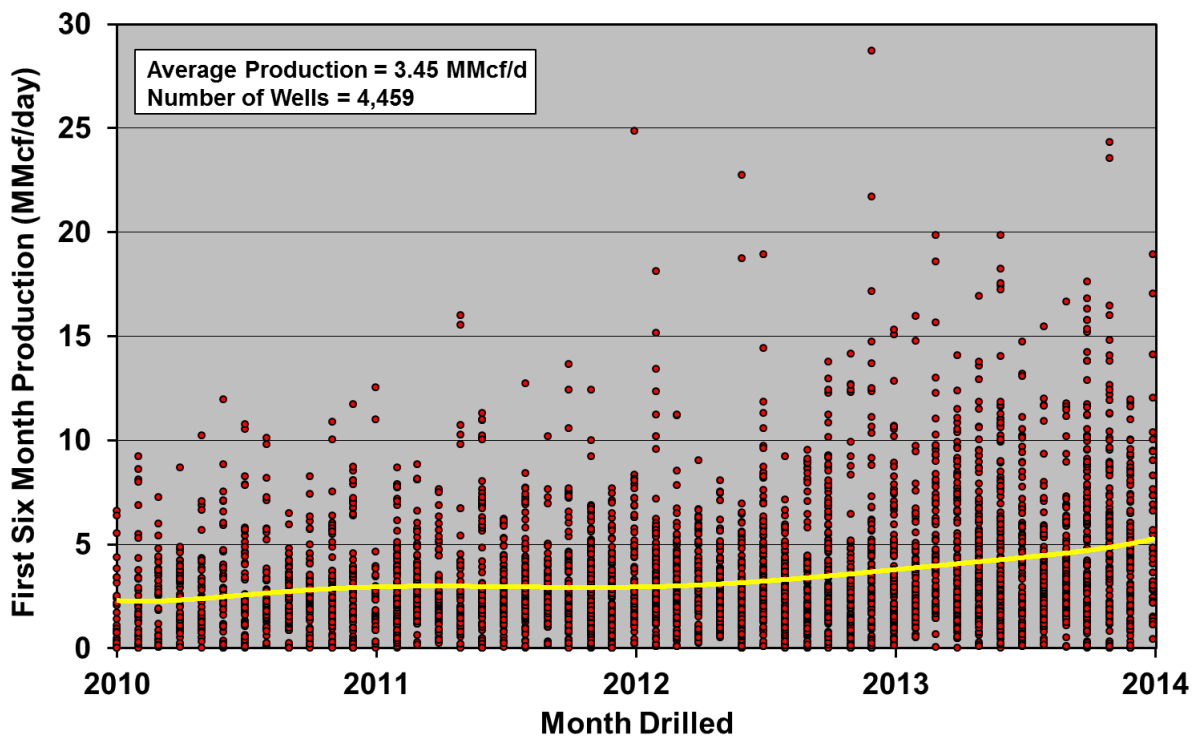


**Figure 3-87. Cumulative gas production and length of time produced for wells in the Marcellus play in Pennsylvania.**

Few wells are greater than five years old, with a mean age of 28 months and a mean cumulative recovery of 1.56 billion cubic feet.<sup>134</sup>

<sup>134</sup> Data from Drillinginfo retrieved September 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells is not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP) which is often focused on by operators. Figure 3-88 illustrates the average daily output over the first six months of production for all wells in the Pennsylvania portion of the Marcellus play (six month IP). The IPs are higher than most other shale plays—averaging 3.45 million cubic feet per day (MMcf/d) for all wells over the 2010 to 2014 period—and are trending upward, through both better technology and concentration of drilling in sweet spots. Again, as with cumulative production, there are a few exceptional wells—4% produced more than 10 MMcf/d—although the average of the most recent wells was about 5 MMcf/d overall. Figure 3-82 illustrates the distribution of IPs in map form illustrating the concentration of drilling in sweet spots.

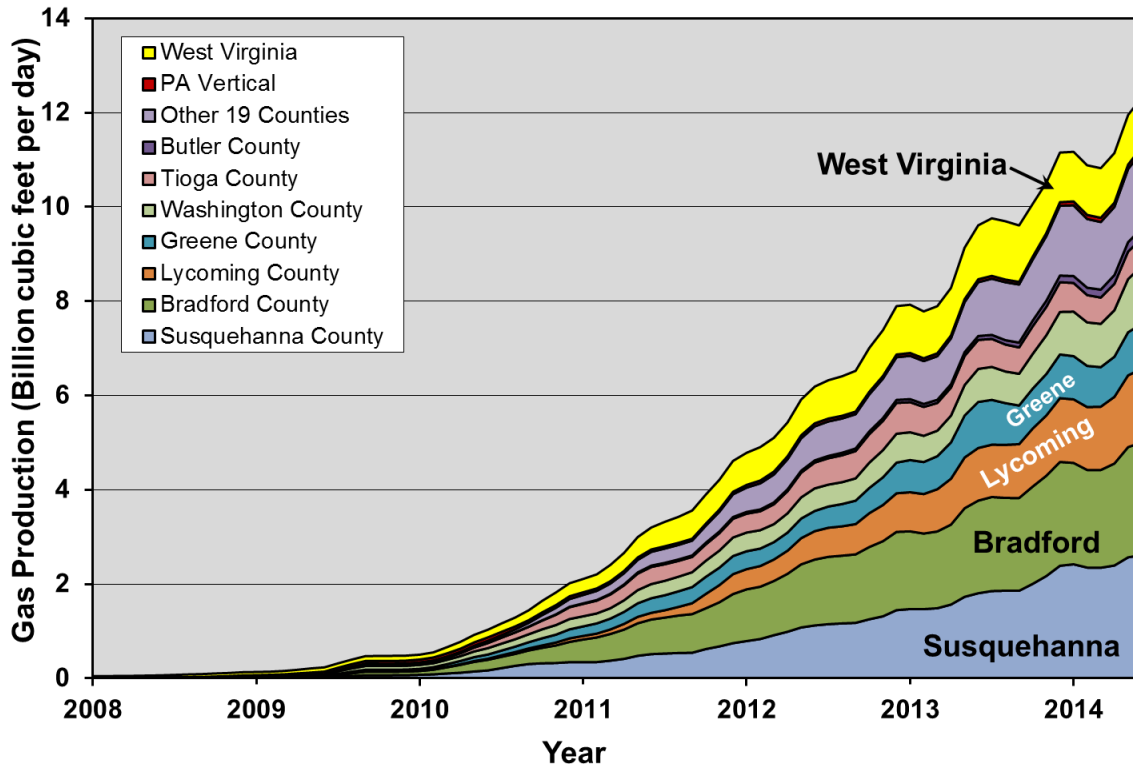


**Figure 3-88. Average gas production over the first six months for all wells drilled in the Marcellus play of Pennsylvania, 2010 to 2014.<sup>135</sup>**

Although there are a few exceptional wells, the average well produced 3.45 MMcf/d over the 2010 to 2014 period, with the most recent wells producing 5 MMcf/d. The trend line indicates mean productivity over time.

<sup>135</sup> Data from Drillinginfo retrieved September 2014.

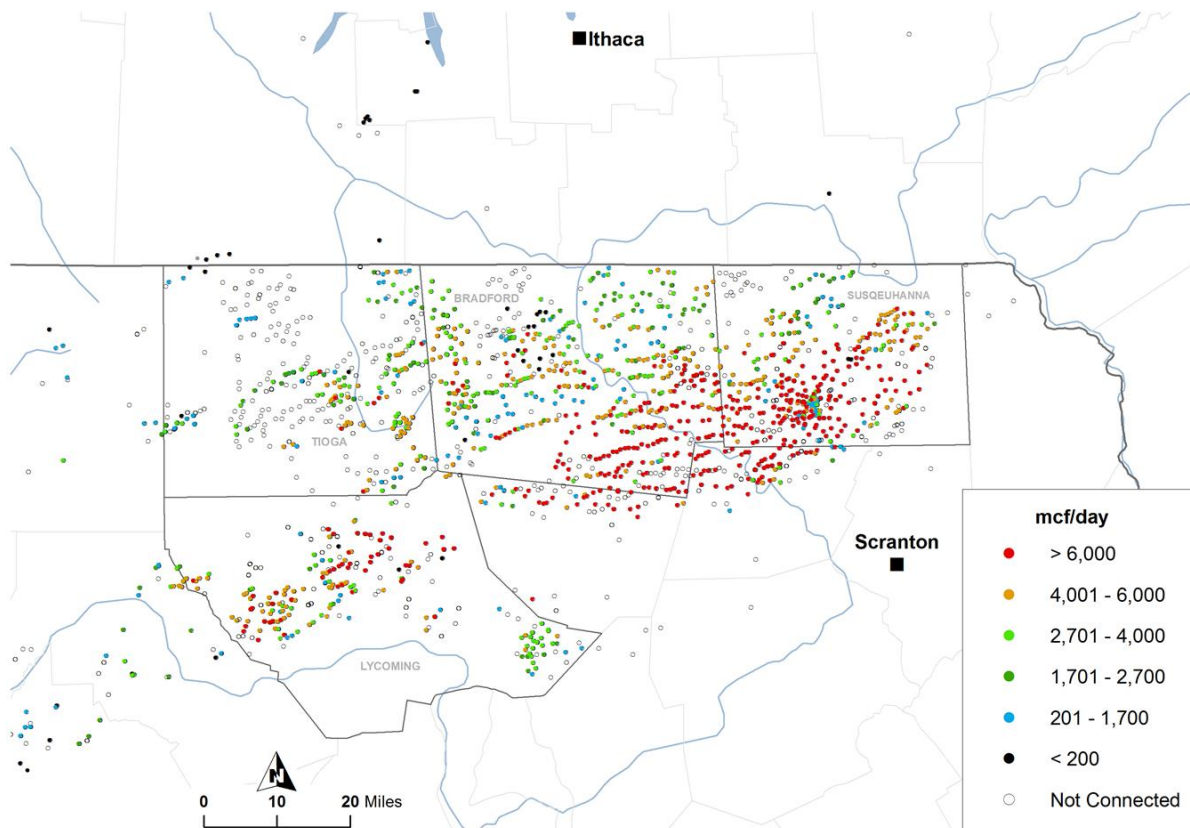
Different counties in the Marcellus display markedly different well quality characteristics which are critical in determining the most likely production profile in the future. Figure 3-89, which illustrates production over time by county and state, shows that in June 2014, two counties in Pennsylvania produced 41% of all Marcellus gas and the top six Pennsylvania counties produced 76%.



**Figure 3-89. Gas production by county in the Marcellus play, 2008 through 2014.<sup>136</sup>**  
 The top six Pennsylvania counties produced 76% of production in June 2014.

<sup>136</sup> Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The location of sweet spots is a function of the combination of many geological characteristics, including depth, thickness, organic matter content, thermal maturity, lithological characteristics allowing fractures to propagate, and the presence of natural fracture systems. Despite the widespread nature of the Marcellus, two sweet spots have been defined that produce the bulk of the gas. The northeast Pennsylvania sweet spot, centered in Susquehanna and Bradford counties, is illustrated with IPs in Figure 3-90, and the southwest Pennsylvania/West Virginia sweet spot, centered on Washington and Greene counties, is illustrated in Figure 3-91. Berman and Pettinger provide an in-depth discussion of the variation in quality of the Marcellus and the price of gas required to be profitable in various areas; they conclude that relatively little commercial gas exists in southern New York State.<sup>137</sup>

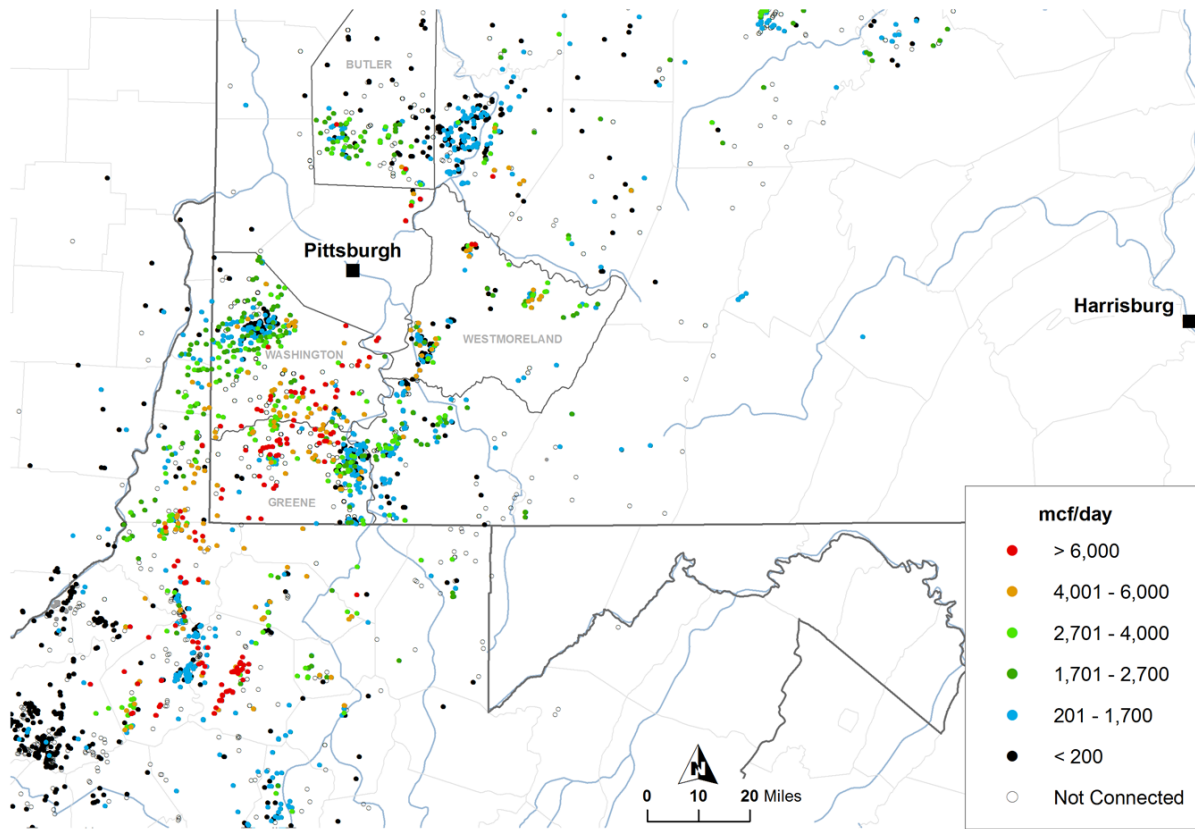


**Figure 3-90. Distribution of wells in the northeast Pennsylvania sweet spot of the Marcellus play, illustrating highest one-month gas production (initial productivity, IP).<sup>138</sup> Bradford and Susquehanna counties produced 41% of all Marcellus gas in June 2014.**

<sup>137</sup> Berman, A.E. and Pettinger, L, 2014, *Resource Assessment of Potentially Producible Natural Gas Volumes from the Marcellus Shale, State of New York*, [http://www.lwny.org/advocacy/natural-resources/hydrofracking/2014/Marcellus-Resource-Assessment-NY\\_0414.pdf](http://www.lwny.org/advocacy/natural-resources/hydrofracking/2014/Marcellus-Resource-Assessment-NY_0414.pdf).

<sup>138</sup> Data from Drillinginfo retrieved September 2014.



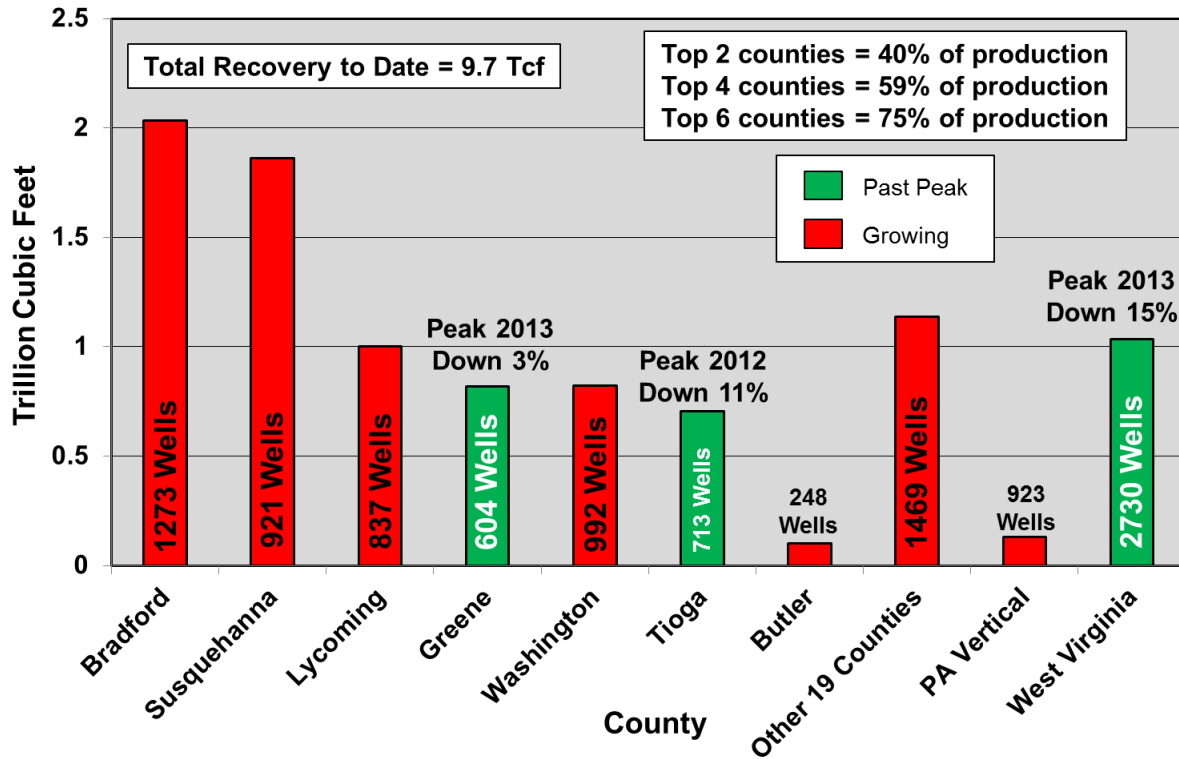


**Figure 3-91. Distribution of wells in the southwest Pennsylvania / northern West Virginia sweet spot of the Marcellus play, illustrating highest one-month gas production (initial productivity, IP).<sup>139</sup>**

Washington and Greene counties along with northern West Virginia produce most of the liquids associated with Marcellus gas.

<sup>139</sup> Data from Drillinginfo retrieved September 2014.

Cumulative production since the field commenced is also concentrated in the sweet spots. As illustrated in Figure 3-92, the top two counties have produced 40% of the gas and the top six have produced 75%. Production in most counties is growing although Greene and Tioga counties in Pennsylvania, and the state of West Virginia in general, are down somewhat from peak production.

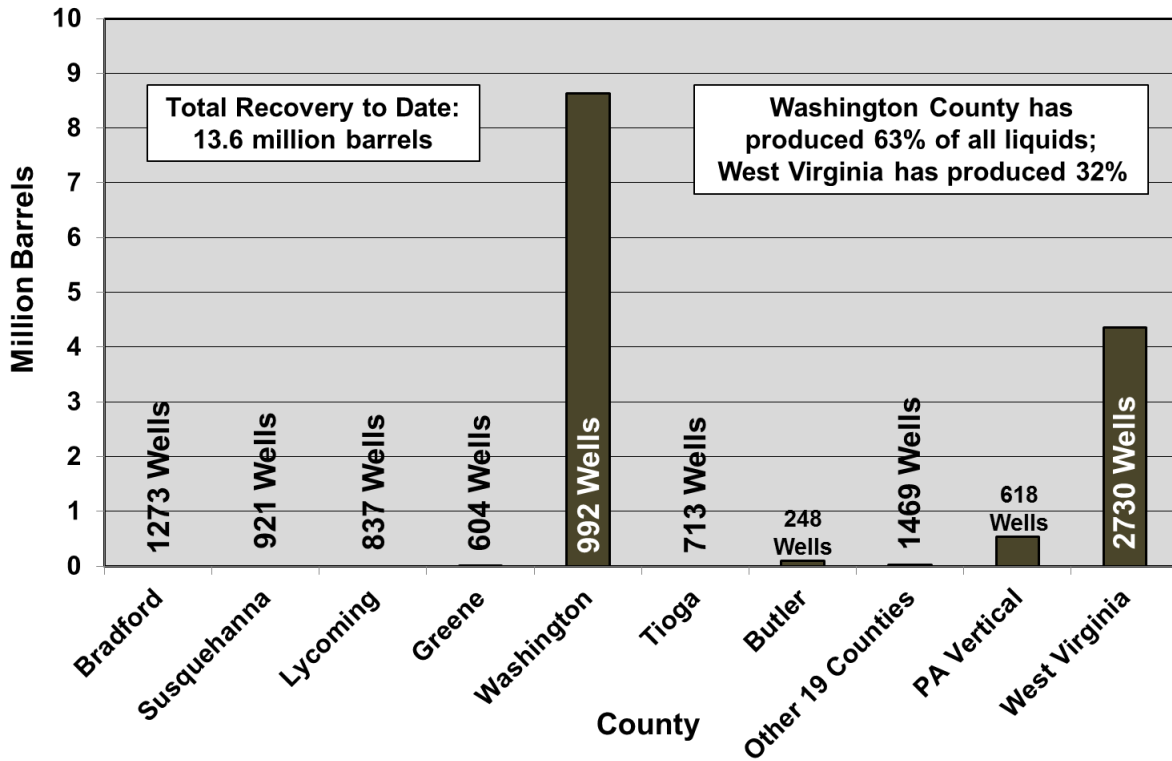


**Figure 3-92. Cumulative gas production by county in the Marcellus play through June 2014.**<sup>140</sup>

The top six counties have produced 75% of the 9.7 trillion cubic feet of gas produced to date. Greene and Tioga counties in Pennsylvania as well as West Virginia are below peak production, but all other areas are rising.

<sup>140</sup> Data from Drillinginfo retrieved September 2014.

The Marcellus also produces limited amounts of natural gas liquids and oil. Most liquids production is in Washington County in southwestern Pennsylvania and in northern West Virginia, as illustrated in Figure 3-93. Although more than 13 million barrels of liquids have been produced since 2005, in the big picture liquids production from the Marcellus is relatively insignificant.

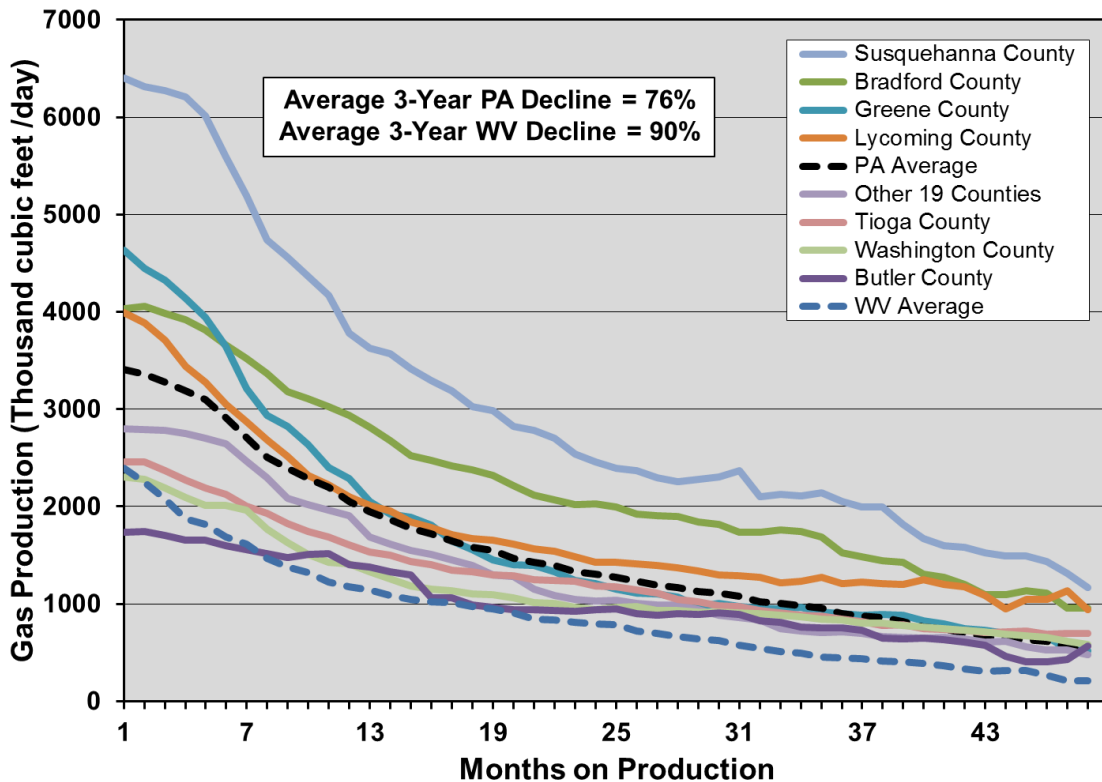


**Figure 3-93. Cumulative liquids production by county in the Marcellus play through 2014.<sup>141</sup>**

Production is concentrated in southwest Pennsylvania and northern West Virginia.

<sup>141</sup> Data from Drillinginfo retrieved September 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost in the order of \$6 million or more each, not including leasing costs and other expenses.<sup>142</sup> The areas of highest quality—the “core” or “sweet spots”—have now been well defined. Figure 3-94 illustrates average horizontal well decline curves by county, which are a measure of well quality (recognizing that future gas production from the Marcellus will be from horizontal, not vertical, wells). Initial well productivities (IPs) from Susquehanna County are more than double those of most other counties (excepting Bradford, Lycoming and Greene). The decline curves from the top four counties are all above the Marcellus average, hence these counties are attracting the bulk of the drilling and investment. Future drilling will have to focus more and more on lesser quality counties.



**Figure 3-94. Average horizontal gas well decline profiles by county and state for the Marcellus play.<sup>143</sup>**

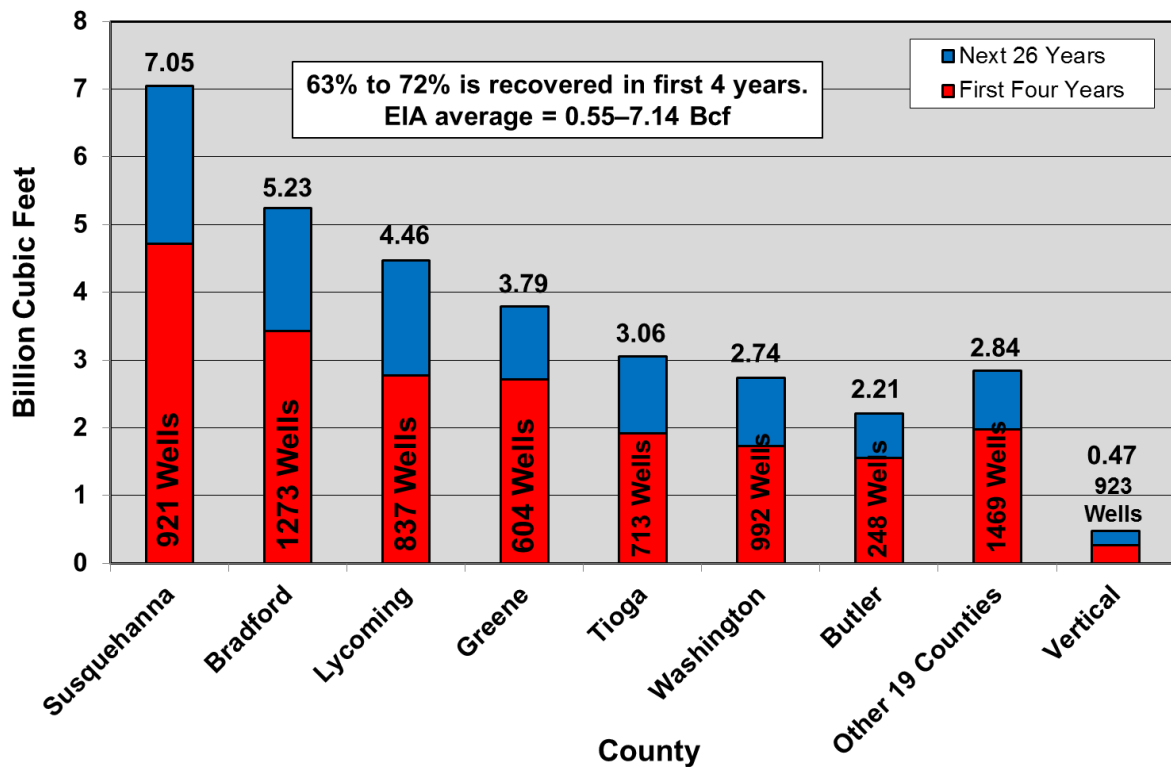
The top four Pennsylvania counties, which have produced much of the gas in the Marcellus, are clearly superior.

<sup>142</sup> Cabot Investor Presentation, December 2013, <http://www.cabotog.com/wp-content/uploads/2013/12/December-2013-Company-Update.pdf>.

<sup>143</sup> Data from Drillinginfo retrieved September 2014.

Another measure of well quality is “estimated ultimate recovery” or EUR—the amount of gas a well will recover over its lifetime. Although to be clear no one knows what the lifespan of a Marcellus well is, given that few of them are more than five years old (see Figure 3-87 and Figure 3-88), EURs provide a useful metric to compare well quality between areas. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-94, assuming well life spans of 30-50 years (as is typical for conventional wells), but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Marcellus. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-94, which exhibits steep initial decline with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-95 illustrates theoretical EURs by county in Pennsylvania for the Marcellus for comparative purposes of well quality. These range from 2.21 to 7.05 billion cubic feet per well, which are comparable to the 0.55 to 7.14 billion cubic feet assumed by the EIA.<sup>144</sup> The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 63% and 72% of an average well’s lifetime production occurs in the first four years.



**Figure 3-95. Estimated ultimate recovery of gas by county for the Marcellus play in Pennsylvania.<sup>145</sup>**

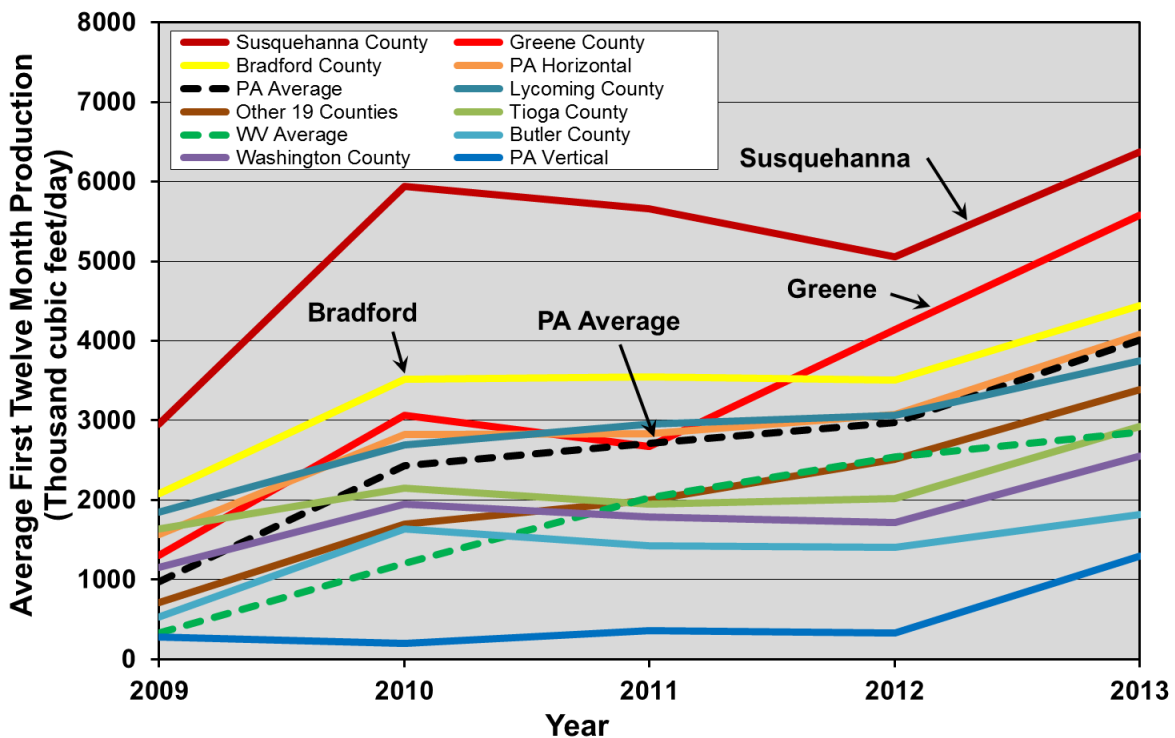
EURs are based on average well decline profiles (Figure 3-94) and a terminal decline rate of 20%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life. The lowest 22 counties average less than half of the EUR of the top county, Susquehanna.

<sup>144</sup> EIA, July 2014, *Oil and Gas Supply Module*, [http://www.eia.gov/forecasts/aeo/nems/documentation/ogsm/pdf/m063\(2014\).pdf](http://www.eia.gov/forecasts/aeo/nems/documentation/ogsm/pdf/m063(2014).pdf).

<sup>145</sup> Data from Drillinginfo retrieved September 2014.

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

Figure 3-96 illustrates the average first year production rate of wells by county. Average well quality has been rising in all areas through application of better technology—longer horizontal laterals, more frack stages, higher volumes of more sophisticated additives, and higher-volume frack treatments. The top three counties—Susquehanna, Greene and Bradford—are significantly higher than the average well productivity of the rest. Considering the large areal extent of the Marcellus play, relatively few wells have been drilled and thus there is still considerable room for more wells in the best areas. The current drilling rate of about 1,300 wells per year is above the 1,000 wells needed to offset field decline at current production levels, so Marcellus production will keep rising in the short to medium term as long as these drilling rates are maintained.



**Figure 3-96. Average first-year gas production rates of wells by county in the Marcellus play, 2009 to 2013.<sup>146</sup>**

Well quality is rising in most areas indicating that better technology—longer horizontal laterals and higher volume frack treatments—are improving productivity. First year production rate in the “other 19” counties, where more than half of the remaining drilling locations are found, is roughly half that of the top two counties.

<sup>146</sup> Data from Drillinginfo retrieved September 2014.

### 3.3.5.4 Number of Wells

A fourth critical parameter is the number of wells that can ultimately be drilled in the Marcellus play. The EIA estimates an area of 16,688 square miles for the “Marcellus Interior” and an additional 869 square miles for the “Marcellus Foldbelt” for a total of 17,566 square miles. They assign an average EUR of 1.59 Bcf to the former and 0.32 to the latter. They also include a “Marcellus Western” area of 2,684 square miles with an average EUR of 0.26 Bcf (which has less than 4% of total unproved resources). Assuming the EIA’s estimates for the Marcellus interior and foldbelt regions are correct—and eliminating the low productivity western area due to its likely lack of economic viability—leaves a play area of 17,566 square miles. Using the EIA’s estimate of 4.3 wells per square mile over this region, a total of 76,415 wells would be developed when the region is completely drilled off, or some ten times the current number of producing wells.

Given that Pennsylvania and West Virginia are relatively densely populated states, with some difficult topography, a more conservative estimate may be that only 80% of the remaining drilling locations are actually accessible to development—allowing for towns, cities, parks and other surface restrictions to development. In this case 63,274 wells would be drilled in total, or an additional 52,564 wells over what are currently in place.

Table 3-5 breaks down the number of yet-to-drill wells by county along with other critical parameters used for determining the future production rates of the Marcellus play.

Parameter	County											Total
	Bradford	Butler	Greene	Lycoming	Susquehanna	Tioga	Washington	Other 19	PA Vertical	PA Total	WV Total	
Production June 2014 (Bcf/d)	2.39	0.21	0.95	1.56	2.62	0.58	1.23	1.63	0.09	11.27	1.05	12.32
% of Field Production	19.40	1.73	7.71	12.67	21.23	4.72	9.98	13.26	0.75	91.46	8.54	100.00
Cumulative Gas (Tcf)	2.03	0.10	0.82	1.00	1.86	0.71	0.82	1.14	0.13	8.62	1.04	9.65
Cumulative Liquids (MMBBL)	0.00	0.09	0.00	0.00	0.00	0.00	8.63	0.03	0.53	9.29	4.35	13.64
Number of Wells	1273	248	604	837	921	713	992	1469	923	7980	2730	10710
Number of Producing Wells	896	142	416	615	662	485	734	862	490	5302	1704	7006
Average EUR per well (Bcf)	5.24	2.21	3.79	4.48	7.05	3.06	2.74	2.84	0.42	3.41	1.67	3.06
Field Decline (%)	25	31	48	37	33	33	32	26	30	32	29	32
3-Year Well Decline (%)	62	57	81	70	68	66	64	75	79	74	81	76
Average First Year Production in 2013 (Mcf/d)	4440	1823	5578	3750	6368	2924	2554	3390	1297	4012	2858	3932
New Wells Needed to Offset Field Decline	135	36	82	154	134	65	155	127	21	899	107	1003
Area in square miles	1161	795	578	1244	832	1137	861	19000	25608	25608	13656	39264
% Prospective	90	90	80	50	75	60	90	34	45	45	45	45
Net square miles	1045	716	462	622	624	682	775	6486	11412	11412	6145	17556
Well Density per square mile	1.22	0.35	1.31	1.35	1.48	1.05	1.28	0.23	0.08	0.70	0.44	0.61
Additional locations to 4.3/sq. Mile	3220	2829	1384	1838	1762	2220	2340	26420	0	42013	23692	65705
Population	62622	183862	38686	116111	43356	41981	207820	N/A	N/A	N/A	N/A	N/A
Total Wells 4.3/sq. Mile	4493	3077	1988	2675	2683	2933	3332	27889	923	49993	26422	76415
Producing Wells 4.3/sq. Mile	4116	2971	1800	2453	2424	2705	3074	27282	490	47315	25396	72711
Risked 80% Total Wells 4.3/sq. Mile	3849	2511	1711	2307	2331	2489	2864	22605	0	40667	21684	63274
Risked 80% Producing Wells 4.3/sq. Mile	3472	2405	1523	2085	2072	2261	2606	21998	0	38422	20658	59570

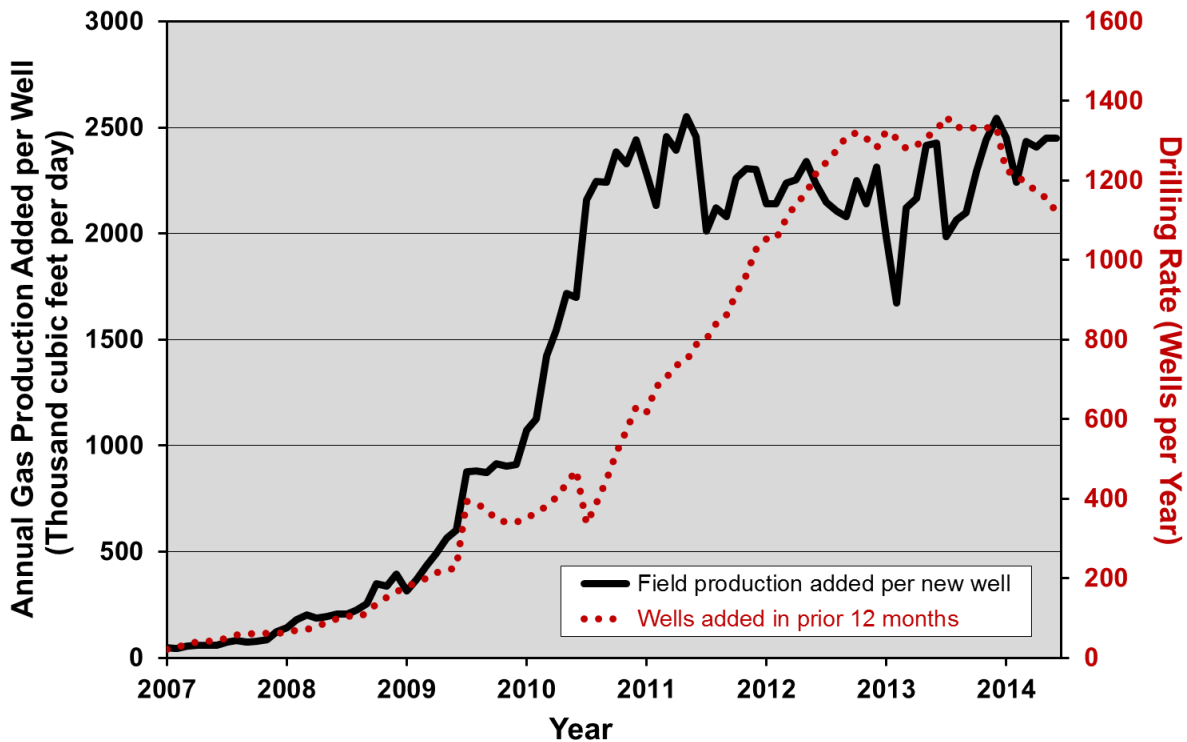
**Table 3-5. Parameters for projecting Marcellus production, by county.**

Area in square miles under “Other” is estimated. Wells by county are horizontal only; “Total” columns include both horizontal and vertical wells.



### 3.3.5.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling. Figure 3-97 illustrates the historical drilling rates in the Marcellus of Pennsylvania. Horizontal drilling rates in Pennsylvania peaked in 2013 at about 1,350 wells per year and have since fallen to current levels of about 1,200 wells per year. Coupled with drilling rates of 120 wells per year in West Virginia, current rates are about 1,320 wells per year. This is considerably higher than the approximately 1,000 wells per year needed to offset field decline at current production rates, hence Marcellus production will keep rising in the short to medium term as long as these drilling rates are maintained.



**Figure 3-97. Annual gas production added per new horizontal well and annual drilling rate and in the Marcellus play, 2007 through 2014.<sup>147</sup>**

Drilling rate peaked in 2013 but remains well above the level needed to offset field decline, hence production will continue to grow in the short to medium term.

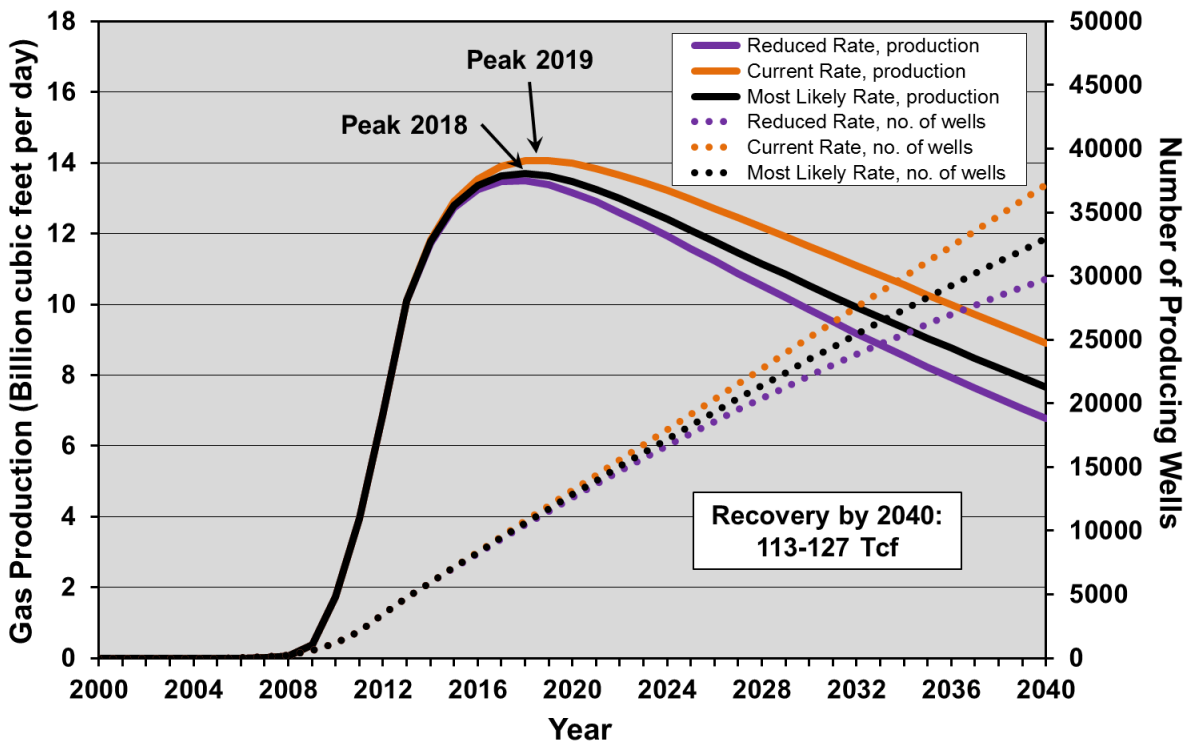
<sup>147</sup> Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

### 3.3.5.6 Future Production Scenarios

Several drilling rate scenarios were used to develop production projections for the Marcellus play given the number of available drilling locations. Figure 3-98 illustrates the production profiles in Pennsylvania for three drilling rate scenarios if 80% of the prospective play area is drillable at 4.3 wells per square mile (for a total of 63,274 wells in the play with 40,677 of them in Pennsylvania). These scenarios are:

- **MOST LIKELY RATE** scenario: Assumes that drilling rate continues at current levels and then gradually declines to 800 wells per year as drilling moves into lower quality parts of the play.
- **HIGH RATE** scenario: Assumes that drilling will continue at current rates until all locations are drilled off.
- **REDUCED RATE** scenario: Assumes that wells will continue at current rates but decline more steeply to 200 wells per year as the last wells are drilled.

In all scenarios drilling continues through 2040 and beyond.



**Figure 3-98. Three drilling rate scenarios of Marcellus gas production in Pennsylvania (assuming 80% of the area is drillable at 4.3 wells per square mile).<sup>148</sup>**

“Most Likely Rate” scenario: drilling continues at 1,200 wells/year, declining to 800/year.

“High Rate” scenario: drilling continues at 1,200 wells/year.

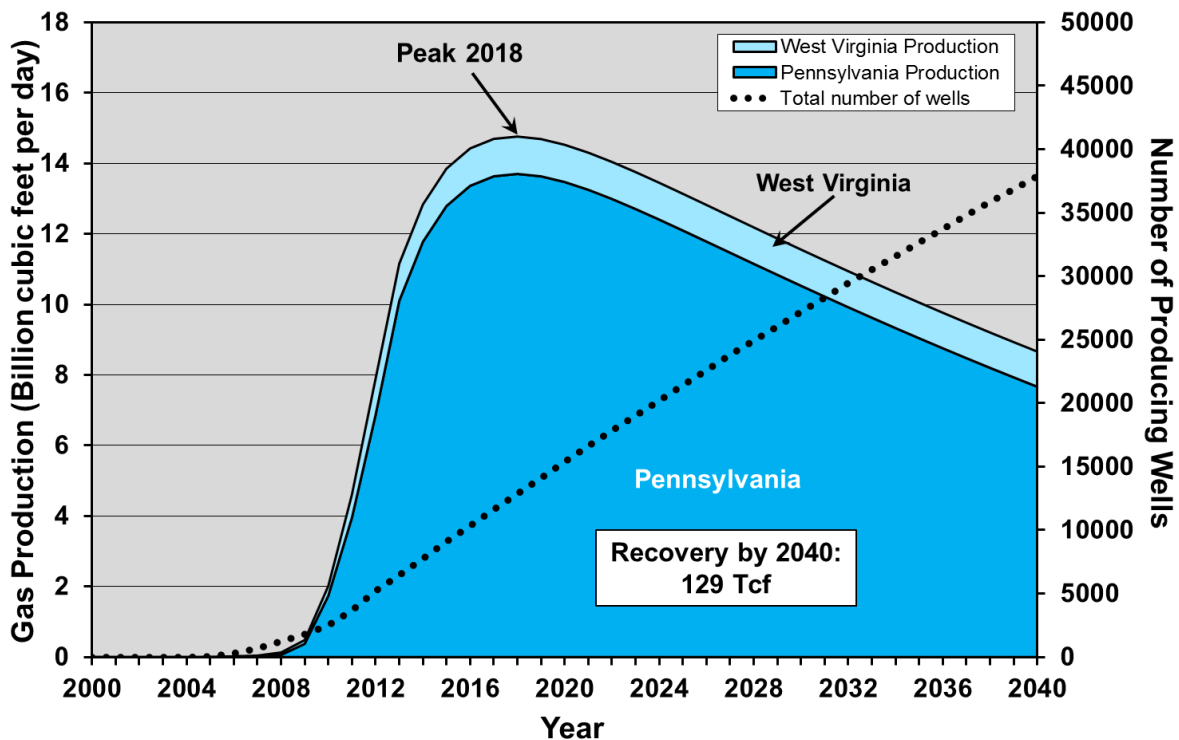
“Reduced Rate” scenario: drilling continues at 1,200 wells/year, declining to 200/year.

<sup>148</sup> Data from Drillinginfo retrieved September 2014.

The drilling rate scenarios have the following results:

1. MOST LIKELY RATE scenario: Total gas recovery by 2040 would be 118.2 trillion cubic feet and drilling would continue beyond 2040. Peak production would occur in 2018.
2. HIGH RATE scenario: Total gas recovery by 2040 would be 127 trillion cubic feet and drilling would continue beyond 2040. Peak production would occur in 2019.
3. REDUCED RATE scenario: Total gas recovery by 2040 would be 113 trillion cubic feet and drilling would continue beyond 2040. Peak production would occur in 2017.

The recovery of between 113 and 127 trillion cubic feet, with 118.2 trillion cubic feet in the “Most Likely Rate” scenario by 2040, makes the Marcellus the most important shale gas play in the U.S. by a wide margin. Nonetheless, it peaks in the 2017-2019 timeframe followed by a long period of decline. If projected production from the Marcellus in West Virginia is included, production in the “Most Likely Rate” scenario will reach nearly 15 Bcf/d, with recovery of 129 trillion cubic feet by 2040 (assuming drilling is continued at the current rate in West Virginia of 120 wells per year) as illustrated in Figure 3-99 .

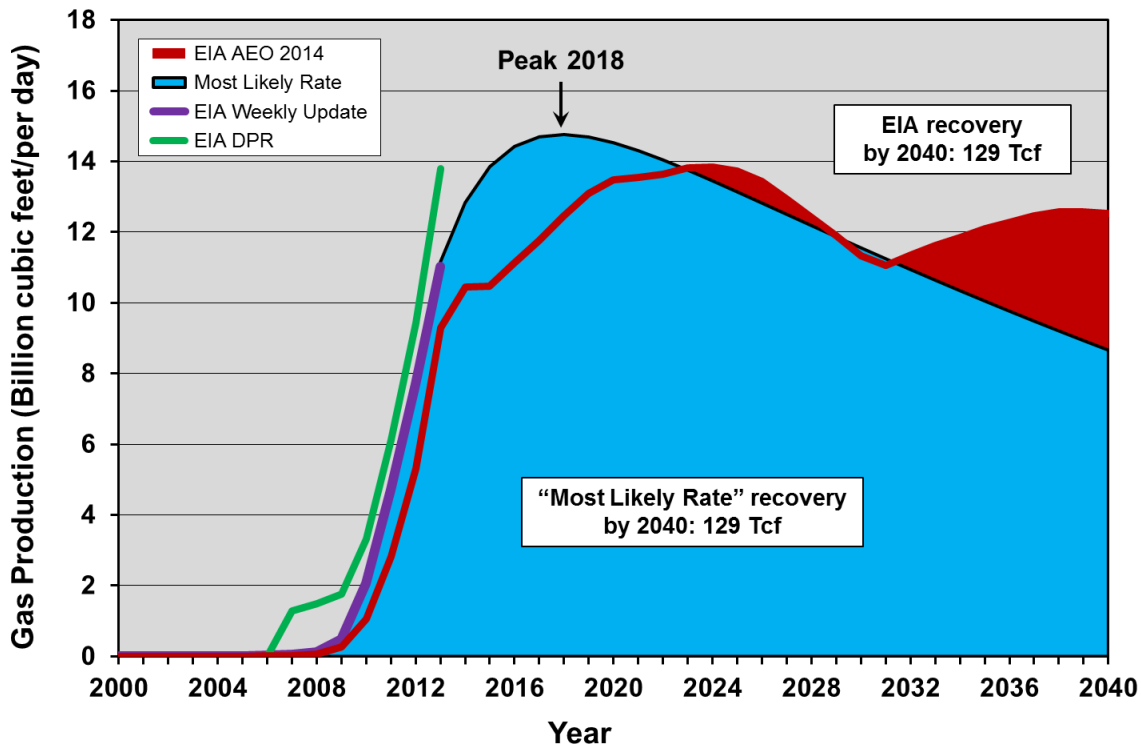


**Figure 3-99. “Most Likely Rate” scenario of Marcellus gas production including both Pennsylvania and West Virginia.**

Total recovery by 2040 of 129 Tcf is 13 times the amount of gas recovered to date. In this “Most Likely Rate” scenario, with the addition of West Virginia, drilling continues at 1,320 wells/year, declining to 920/year.

### 3.3.5.7 Comparison to EIA Forecast

Figure 3-100 illustrates the EIA’s projection for Marcellus production through 2040 compared to the “Most Likely Rate” scenario. The EIA projects recovery by 2040 of 129 Tcf to meet its reference case forecast, which coincidentally is exactly the same quantity as projected in the “Most Likely Rate” scenario. The shape of the EIA production profile in its reference case, however, appears to underestimate past and current production—even compared to its own independent estimates (*Natural Gas Weekly Update* and *Drilling Productivity Report*<sup>149</sup>)—and overestimate production in later years, beyond 2024. The EIA projects a peak in 2024 at 13.8 Bcf/d—lower than the 14.8 Bcf/d peak in 2018 in this report—and generally higher production in the post-2022 timeframe.



**Figure 3-100. EIA reference case for Marcellus shale gas<sup>150</sup> vs. this report’s “Most Likely Rate” scenario, 2000 to 2040.**

The EIA underestimates past and current production compared to the “Most Likely Rate” scenario and its own independent estimates,<sup>151</sup> but overestimates production in later years. The EIA forecast is made on a “dry gas” basis, whereas the “Most Likely Rate” scenario forecast is made on a “raw gas” basis.

<sup>149</sup> EIA, *Natural Gas Weekly Update*, retrieved October 2014, <http://www.eia.gov/naturalgas/weekly>. EIA, *Drilling Productivity Report*, retrieved October 2014, <http://www.eia.gov/petroleum/drilling>.

<sup>150</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>151</sup> EIA, *Natural Gas Weekly Update*, retrieved October 2014, <http://www.eia.gov/naturalgas/weekly>. EIA, *Drilling Productivity Report*, retrieved October 2014, <http://www.eia.gov/petroleum/drilling>.

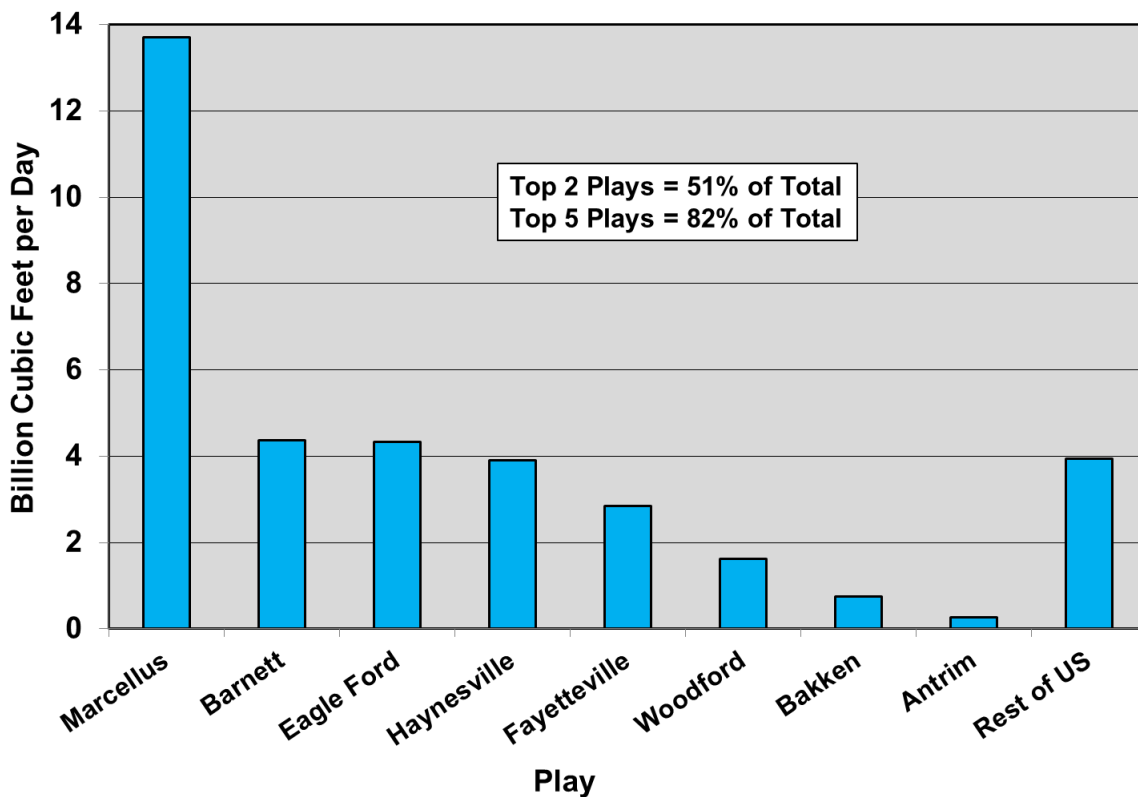
### 3.3.5.8 Marcellus Play Analysis Summary

Several things are clear from this analysis:

1. Marcellus production is growing strongly and drilling rates are sufficient to see continued growth through 2018. There is a significant backlog of wells drilled but not connected—estimated at over 2,000 wells—which will serve to maintain productive well additions in the near term even if rig count and new well drilling declines.
2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Current drilling rates of 1,320 wells per year are considerably above the roughly 1,000 wells per year required to offset field decline at current production rates. Offsetting field decline requires an investment of \$6 billion per year for drilling (assuming \$6 million per well), not including leasing, infrastructure and operating costs. Future production profiles are most dependent on drilling rate and to a lesser extent on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Although drilling in the sweet spots is certainly economic at current prices, prices will have to increase to justify drilling in lower quality parts of the play when sweet spots are exhausted.
3. Production in the “Most Likely Rate” scenario will rise to 15 Bcf/d at peak in the 2018 timeframe followed by a gradual decline. The “High” drilling rate scenario would move this peak forward to 2019 at more than 15 Bcf/d. Drilling will continue in all scenarios until well beyond 2040.
4. The projected recovery of 129 Tcf by 2040 in the “Most Likely Rate” scenario, is the same as the EIA reference case. However, the EIA has underestimated near term production rates and overestimated production rates in the longer term.
5. These projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained to keep production up. This is not a sure thing as drilling in the poorer quality parts of the play will require higher gas prices to make it economic. Failure to maintain drilling rates will result in a lower production profile.
6. More than four times the current number of wells will need to be drilled by 2040 to meet production projections.
7. The projections in this report assume that of the total number of wells that could be drilled if 100% of the surface area was accessible for drilling at 4.3 wells per square mile, only 80% of the undrilled locations will be available, owing to surface land use. Any additional restrictions on land use would further limit the number of wells that could be drilled and result in lower production.

### 3.4 MAJOR U.S. TIGHT OIL PLAYS WITH SIGNIFICANT ASSOCIATED SHALE GAS PRODUCTION

Two tight oil plays which were analyzed in depth in Part 2 (Tight Oil) of this report also produce significant quantities of natural gas. As of June 2014, the Eagle Ford play ranked third and the Bakken play ranked seventh in terms of gas output from U.S. shale plays, as illustrated in Figure 3-101.<sup>152</sup> These plays are analyzed for future gas production below. Given that they are primarily oil plays, drilling rates and progression of drilling from sweet spots to lower quality areas will be governed by oil production—hence the analysis of these plays relies on the analysis in Part 2 of this report in order to determine likely future production.



**Figure 3-101. U.S. shale gas daily production by play as of June 2014.<sup>153</sup>**

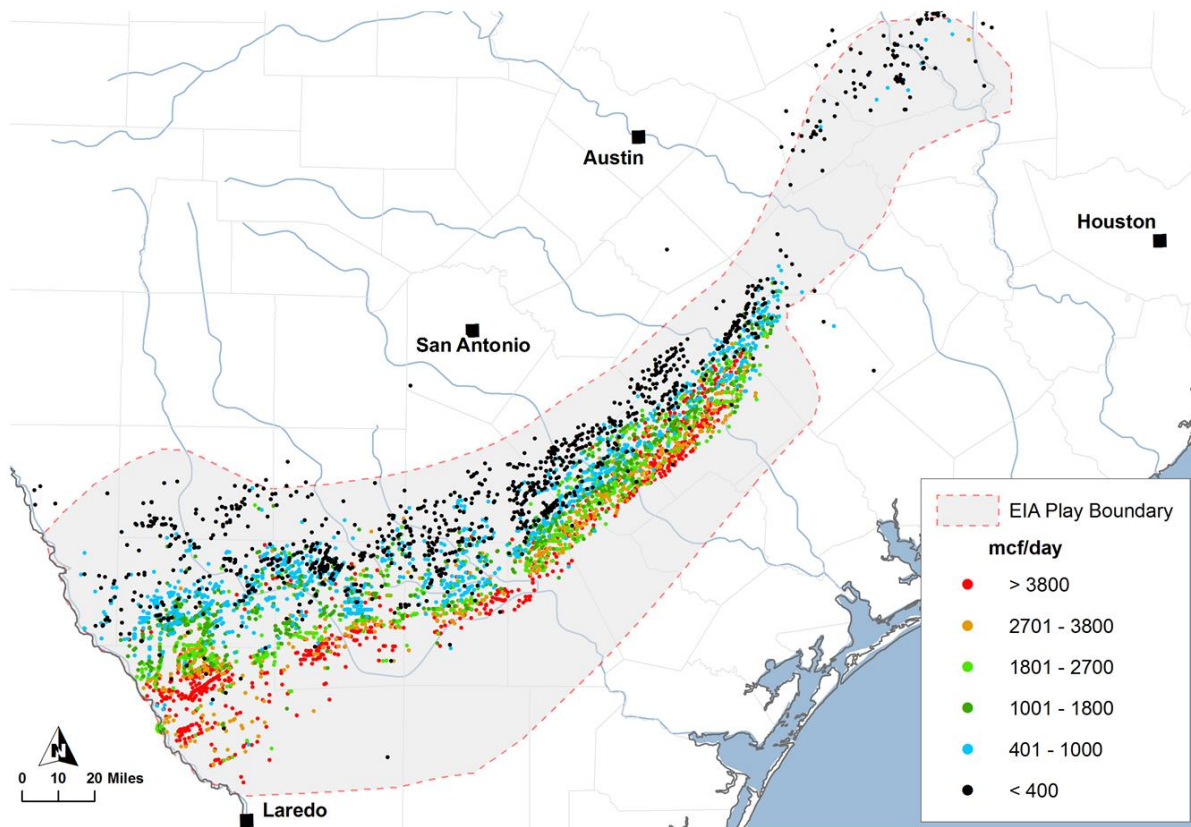
The Bakken tight oil play and especially the Eagle Ford tight oil play are also significant producers of shale gas.

<sup>152</sup> EIA, *Natural Gas Weekly Update*, retrieved July 2014, [http://www.eia.gov/naturalgas/weekly/archive/2014/07\\_24/index.cfm](http://www.eia.gov/naturalgas/weekly/archive/2014/07_24/index.cfm). Note that the EIA in October 2014 published an estimate from the Utica of 1.174 Bcf/d, but this appears to be total gas production from Ohio, not specifically shale gas from the Utica Play; <http://www.eia.gov/naturalgas/weekly> retrieved October 9, 2014.

<sup>153</sup> EIA, *Natural Gas Weekly Update*, retrieved July 2014, [http://www.eia.gov/naturalgas/weekly/archive/2014/07\\_24/index.cfm](http://www.eia.gov/naturalgas/weekly/archive/2014/07_24/index.cfm)

### 3.4.1 Eagle Ford Play

The Eagle Ford play is divided into oil-, condensate- and gas-windows with increasing depth as discussed in Part 2 of this report. Therefore the best locations for oil production are not necessarily the same as the best locations for gas production. Figure 3-102 illustrates the distribution of well quality for gas production in the Eagle Ford as defined by highest one-month production (IP).

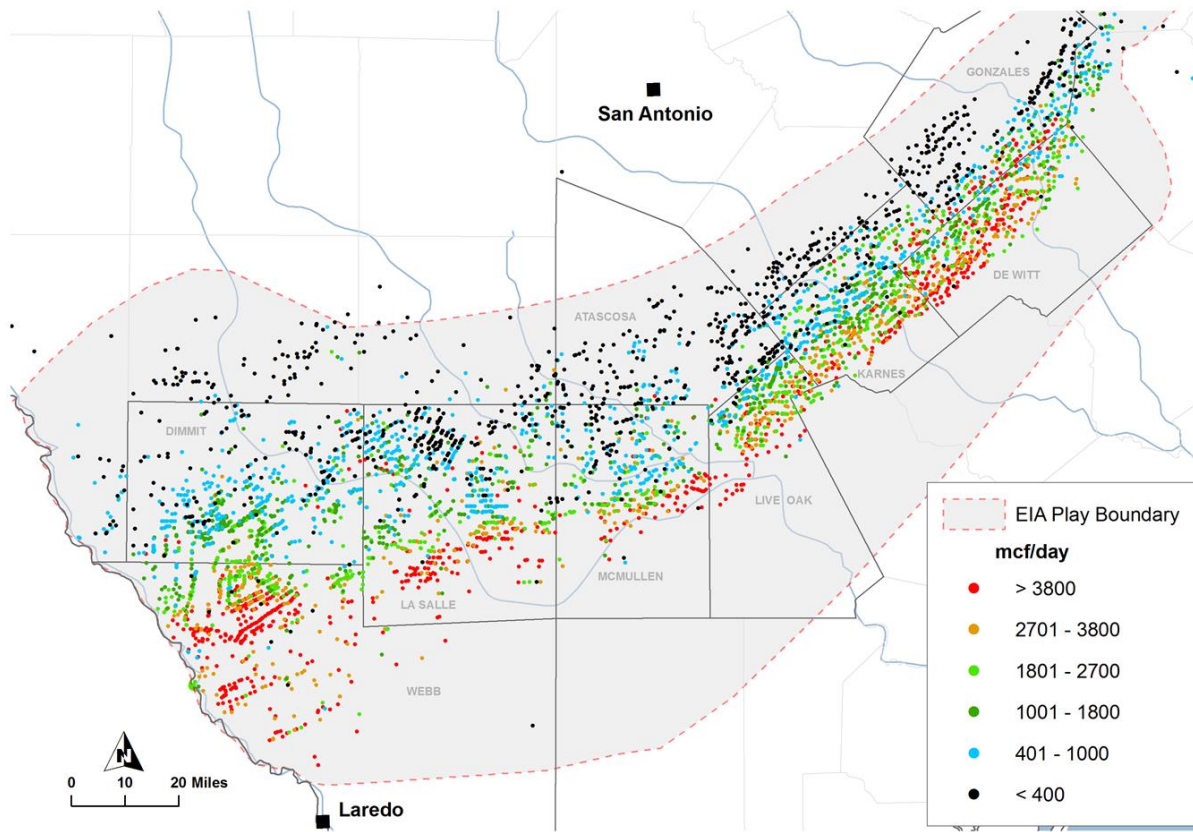


**Figure 3-102. Distribution of wells in the Eagle Ford play as of mid- 2014, illustrating highest one-month gas production (initial productivity, IP).<sup>154</sup>**

Well IPs are categorized approximately by percentile; see Appendix.

<sup>154</sup> Data from Drillinginfo retrieved August 2014.

Figure 3-103 provides a closer view of the main gas production area along with the counties utilized in the analysis.

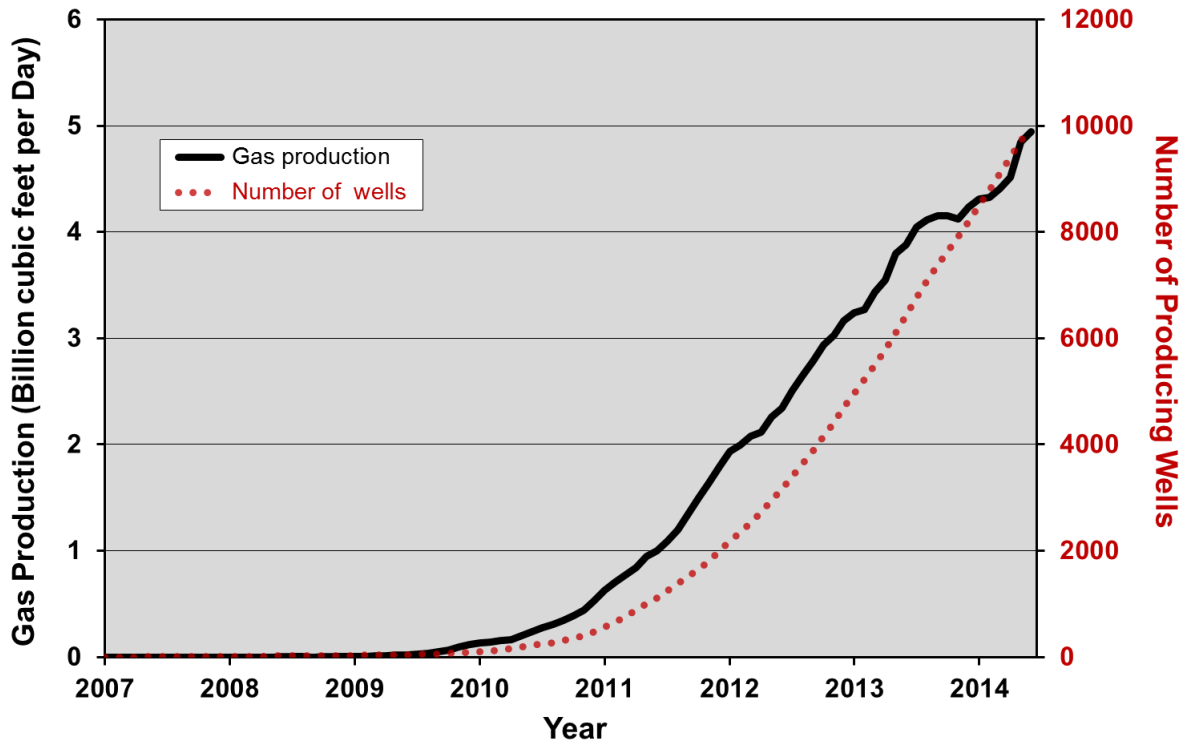


**Figure 3-103. Detail of the Eagle Ford play showing distribution of wells as of mid-2014, illustrating highest one-month gas production (initial productivity, IP).<sup>155</sup>**  
 Well IPs are categorized approximately by percentile; see Appendix.

<sup>155</sup> Data from Drillinginfo retrieved August 2014.



Figure 3-104 illustrates gas production in the Eagle Ford from 2007 through mid-2014. Production is nearing 5 Bcf/d from just over 10,000 producing wells.



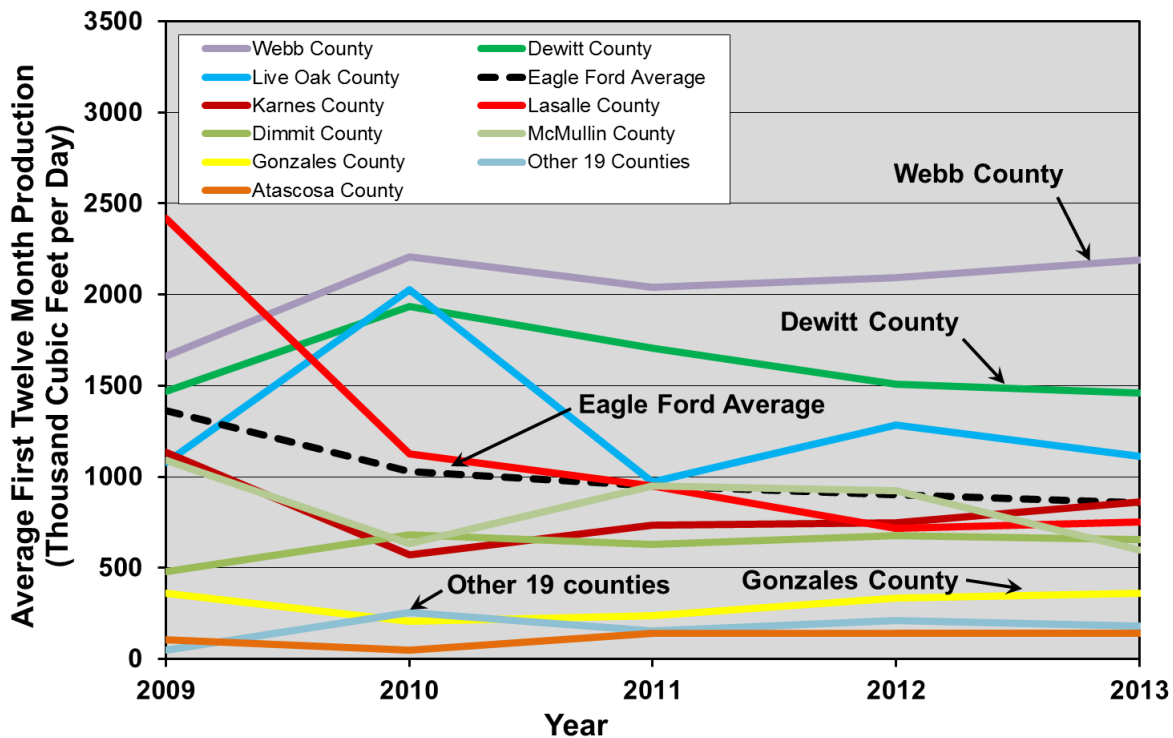
**Figure 3-104. Eagle Ford play shale gas production and number of producing wells, 2007 through 2014.<sup>156</sup>**

Gas production data are provided on a “raw gas” basis.

<sup>156</sup> Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

### 3.4.1.1 Critical Parameters

Other critical parameters include the average well decline, which is 80% over 3 years, and the average field decline, which is 47% for gas wells. The distribution of gas production by county is illustrated in Part 2 of this report, and the evolution of well quality over time is illustrated in Figure 3-105.



**Figure 3-105. Average first-year gas production rates of wells by county in the Eagle Ford play, 2009 to 2013.<sup>157</sup>**

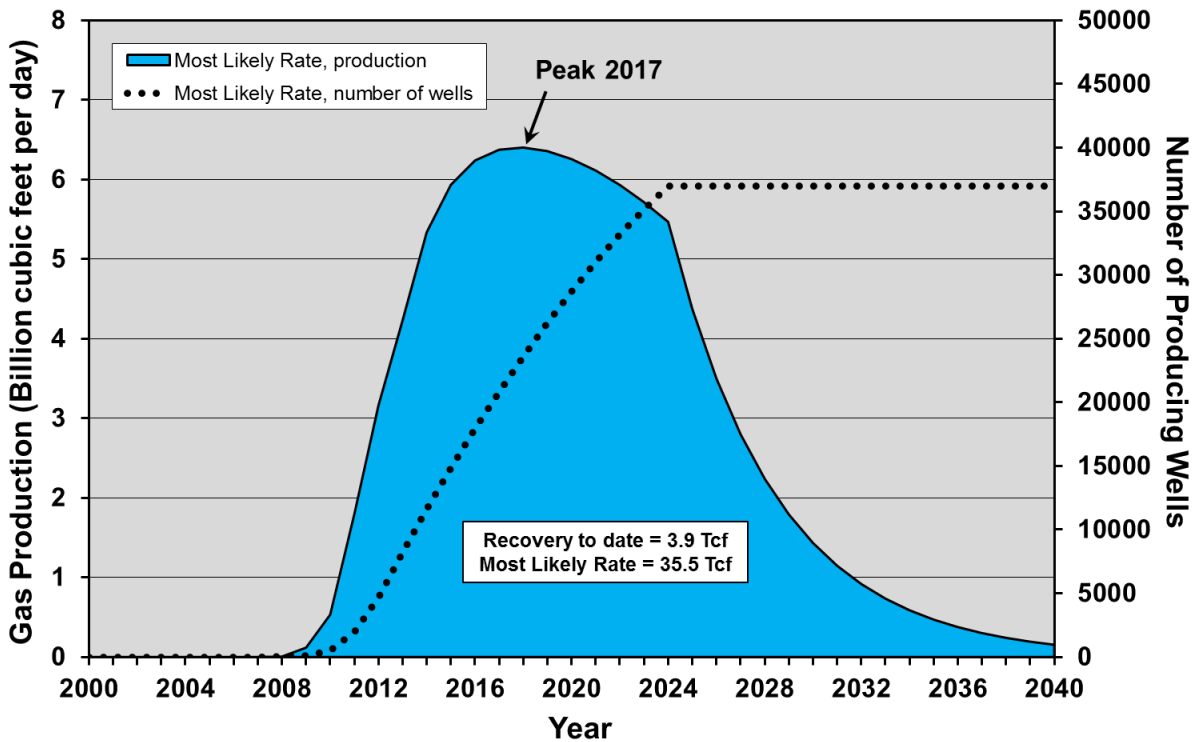
Gas production is an important economic component of Eagle Ford wells as it comprises nearly 40% of the energy produced on average from the play (the distribution of energy production from the Eagle Ford on a “barrels of oil equivalent” basis is illustrated in Part 2 of this report). As can be seen in Figure 3-105, the average well quality from a gas production point of view has been declining. This is likely a result of drilling moving into areas more favorable for oil production and less favorable for gas production, and is not an indicator of what well quality for gas production will look like later on as sweet spots for oil production become saturated with wells. Webb County, for example, which is the best county for gas production but one of the worst for oil production, will see a lot more drilling in later stages of the play’s development. Hence the average well quality, from a gas production point of view, is likely to increase in later stages of play development.

<sup>157</sup> Data from Drillinginfo retrieved September 2014.

### 3.4.1.2 Future Production Scenarios

Given that oil production is the driving force in the Eagle Ford at the current time, the “Most Likely Rate” scenario of the “Realistic Case” for oil production as outlined in Part 2 of this report is used for projection of future Eagle Ford gas production. This scenario assumes that more than 37,000 wells will be drilled in total (compared to just over 10,000 wells at present), and that drilling will continue at current rates of 3,550 wells per year and gradually fall to 2,000 wells per year as the play is drilled off. It also assumes that well quality for gas production will rise 50% from current levels as drilling moves from oil-prone areas back into gas-prone areas later in the play’s development.

Figure 3-106 illustrates the “Most Likely Rate” projection for Eagle Ford production (see Part 2 of this report for other key parameters used for this projection). Production is forecast to rise considerably from current levels to nearly 6.5 Bcf/d by 2017 before declining. Total gas recovery through 2040 will be about 35.5 Tcf, or nearly 10 times the amount produced from the play so far.



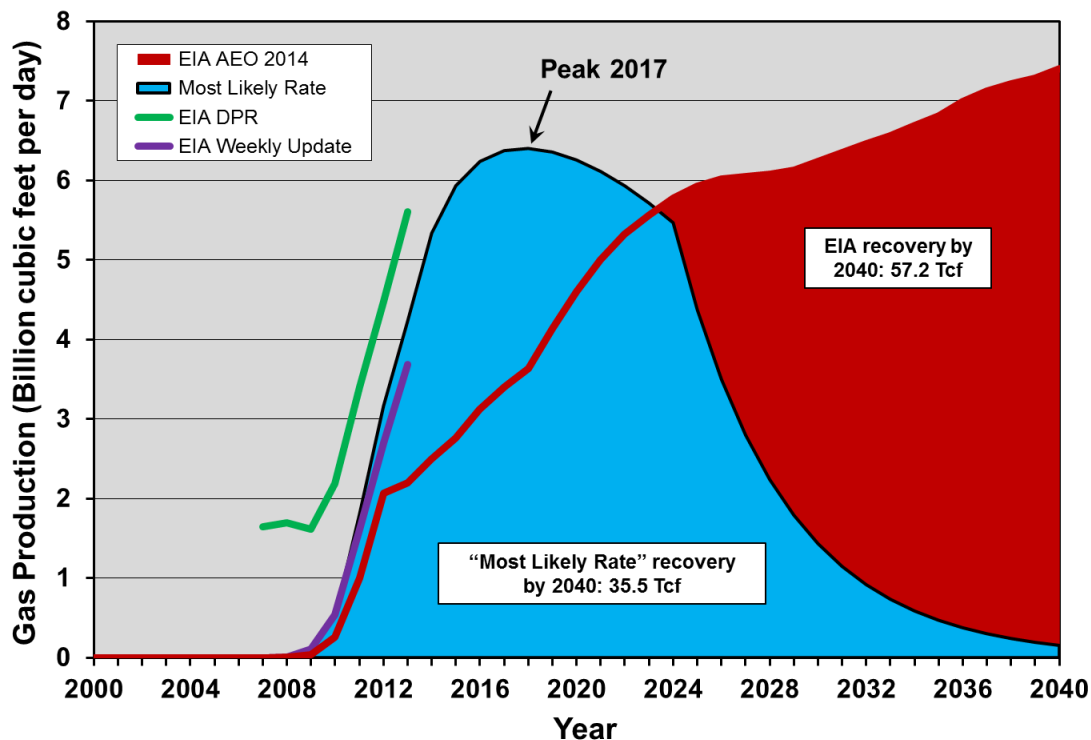
**Figure 3-106. “Most Likely Rate” scenario of Eagle Ford production for gas in the “Realistic Case” (80% of the remaining area is drillable at six wells per square mile).**

This projection assumes that well quality for gas production will rise in later stages of play development as drilling moves back into gas prone parts of the play.

### 3.4.1.3 Comparison to EIA Forecast

Figure 3-107 illustrates the comparison of the “Most Likely” drilling rate scenario to the EIA’s reference case forecast. Several points are evident:

- The EIA is underestimating current production in the Eagle Ford in its forecast and highly overestimating production later on, after 2024. The EIA’s near term forecast is invalidated by its own data as shown in Figure 3-107, which shows much higher current production.
- The EIA forecasts a recovery of 57.2 Tcf over the 2000-2040 period, or 21.7 Tcf more than the “Most Likely Rate” scenario over the same period.
- The EIA forecasts continuing growth in Eagle Ford gas production to an all-time high well over 7 Bcf/d in 2040. This is unrealistic given the data.



**Figure 3-107. EIA reference case for Eagle Ford shale gas<sup>158</sup> vs. this report’s “Most Likely Rate” scenario of the “Realistic Case,” 2000 to 2040**

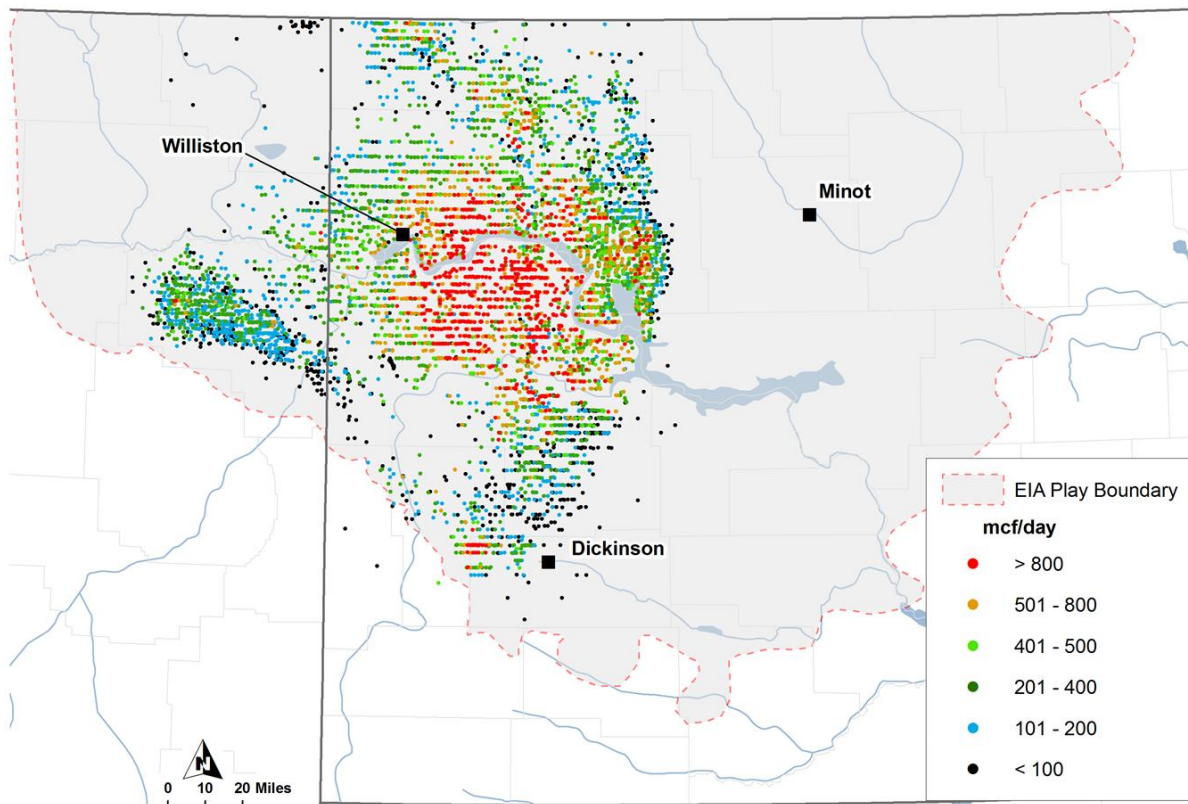
Also shown are the EIA’s Eagle Ford gas production statistics from its *Drilling Productivity Report* and its *Natural Gas Weekly Update*,<sup>159</sup> which contradict the early years of its AEO 2014 forecast. The EIA forecast is made on a “dry gas” basis, whereas the “Most Likely Rate” scenario forecast is made on a “raw gas” basis.

<sup>158</sup> EIA, *Annual Energy Outlook 2014*.

<sup>159</sup> EIA, *Drilling Productivity Report*, retrieved October 2014, <http://www.eia.gov/petroleum/drilling>; EIA, *Natural Gas Weekly Update*, retrieved October 2014, <http://www.eia.gov/naturalgas/weekly>.

### 3.4.2 Bakken Play

The Bakken play’s areas of highest gas production per well are shifted a few miles west of the areas of highest oil production per well, but are generally in fairly close proximity. Figure 3-108 illustrates the distribution of well quality for gas production in the Bakken as defined by highest one-month production (IP)—see Part 2 of this report for a comparison to well quality for oil production.

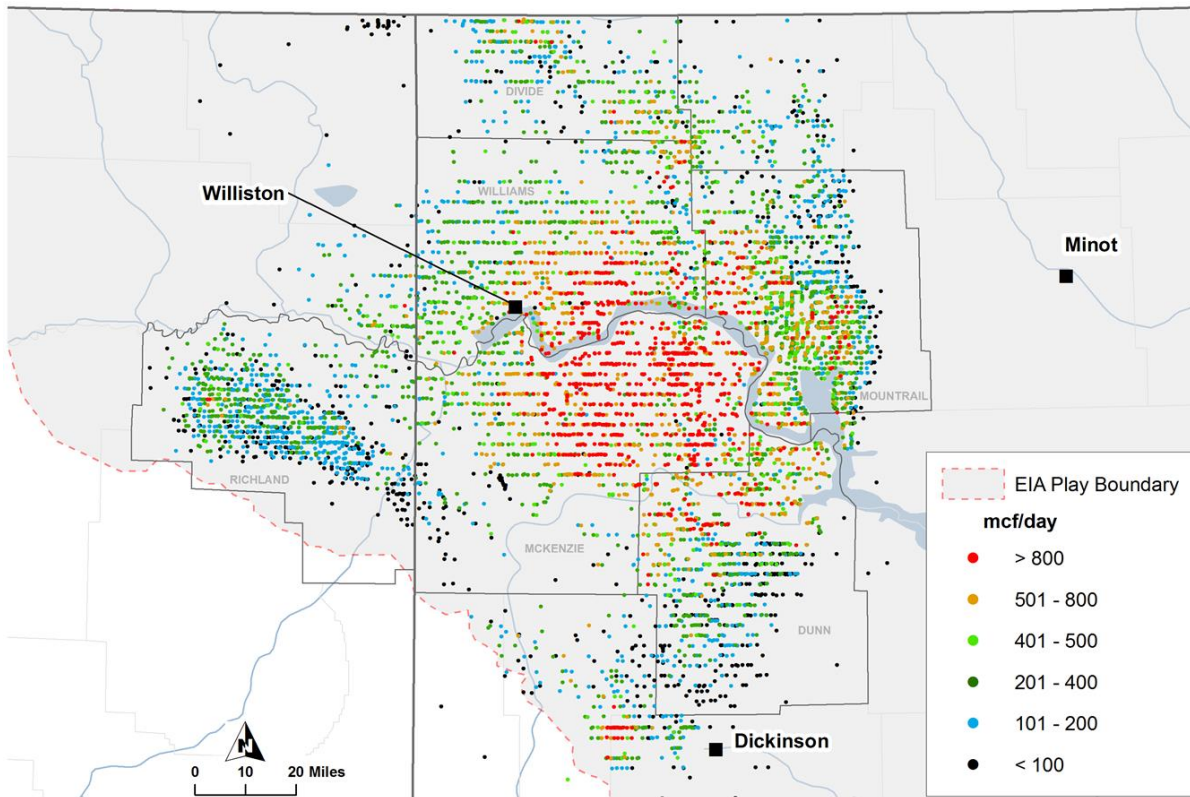


**Figure 3-108. Distribution of wells in the Bakken play as of mid-2014 illustrating highest one-month gas production (initial productivity, IP).<sup>160</sup>**

Well IPs are categorized approximately by percentile; see Appendix.

<sup>160</sup> Data from Drillinginfo retrieved August 2014.

Figure 3-109 provides a closer view of the main gas production area along with the counties utilized in the analysis.

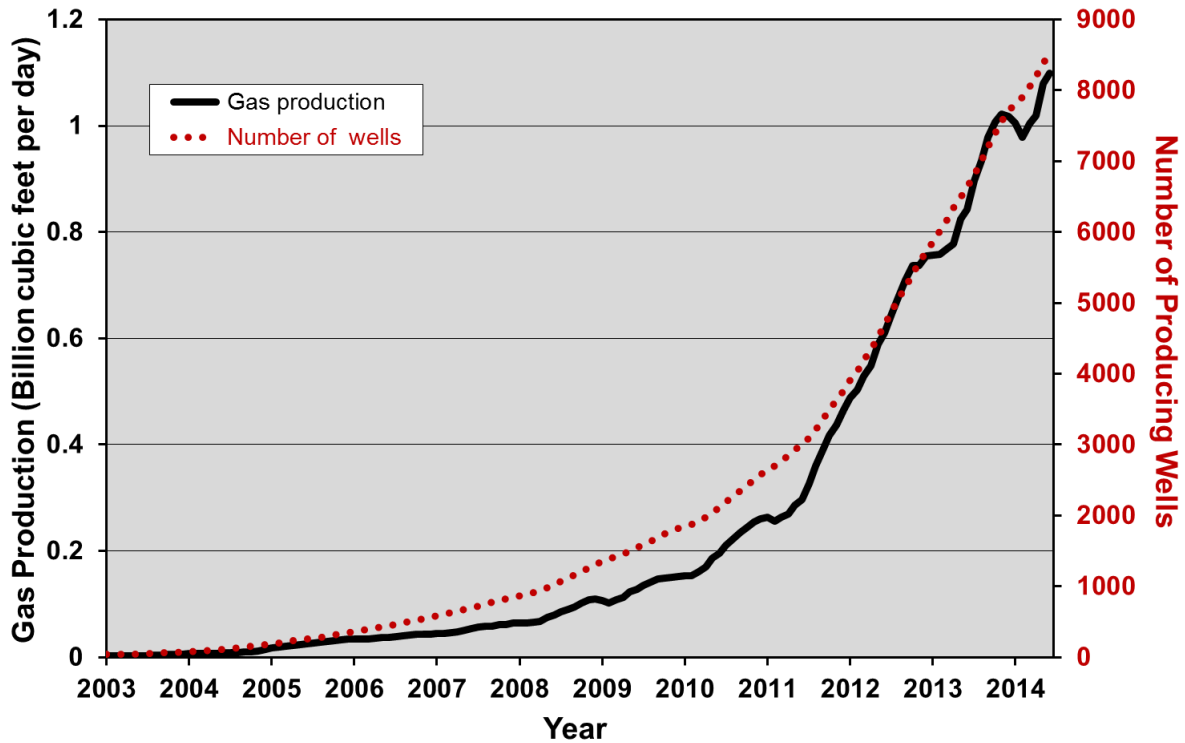


**Figure 3-109. Detail of the Bakken play showing distribution of wells as of mid-2014, illustrating highest one-month gas production (initial productivity, IP).<sup>161</sup>**

Well IPs are categorized approximately by percentile; see Appendix.

<sup>161</sup> Data from Drillinginfo retrieved August 2014.

Figure 3-110 illustrates gas production in the Bakken from 2003 through mid-2014. Production is about 1.1 Bcf/d from over 8,500 producing wells.



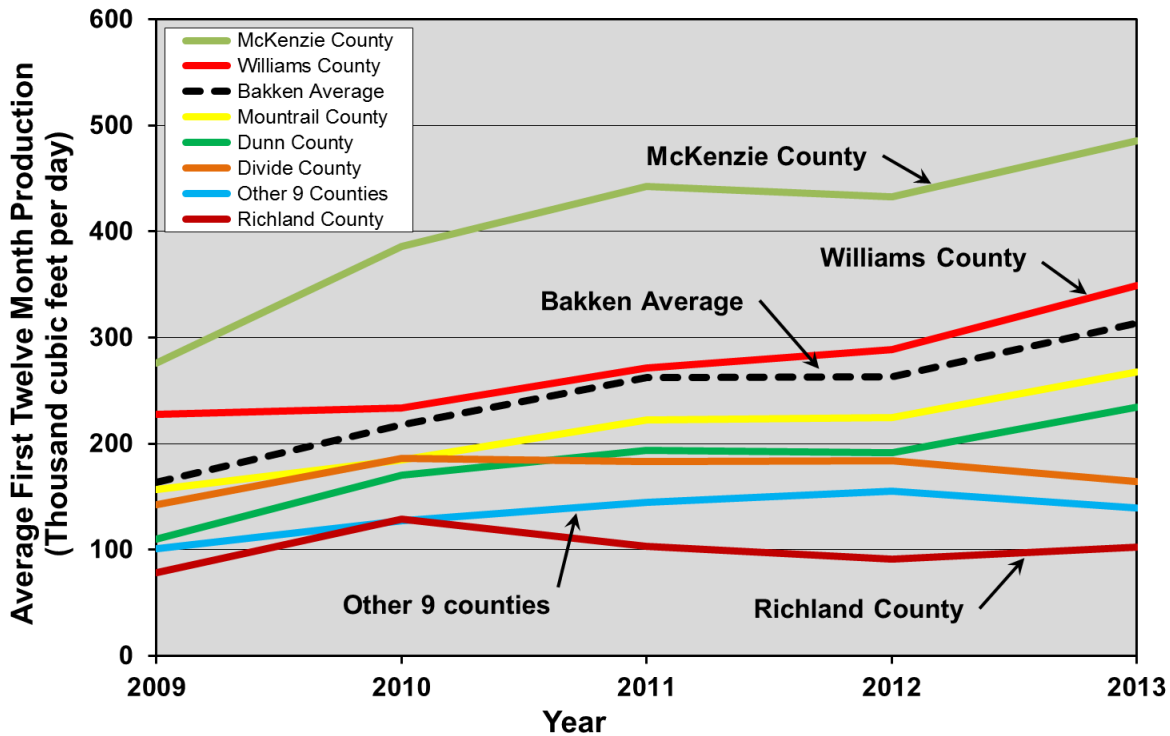
**Figure 3-110. Bakken play shale gas production and number of producing wells, 2003 through 2014.**<sup>162</sup>

Gas production data are provided on a “raw gas” basis.

<sup>162</sup> Data from Drillinginfo retrieved September 2014.

### 3.4.2.1 Critical Parameters

Other critical parameters include the average well decline, which is 81% over 3 years, and the average field decline, which is 41% for gas wells. The evolution of well quality over time for gas production is illustrated in Figure 3-111.



**Figure 3-111. Average first-year gas production rates of wells by county in the Bakken play, 2009 to 2013.<sup>163</sup>**

Gas production is a less important economic component of Bakken wells than for the Eagle Ford as only about 16% of the energy produced from the play is gas, and much of the gas is flared in areas remote from infrastructure (roughly 30% of gas production is flared).<sup>164</sup> New regulations on flaring will likely reduce the amount in future and divert more of this production to sales.<sup>165</sup> As can be seen in Figure 3-111, the average well quality from a gas production point of view has been increasing in the top four counties and declining or flat in the other 11 counties. Given the close proximity of high quality oil wells to high quality gas wells, the decline in well quality for gas as drilling moves to lower quality parts of the play is expected to parallel the decline in well quality for oil.

<sup>163</sup> Data from Drillinginfo retrieved September 2014.

<sup>164</sup> Styles, Geoffrey, August 2014, *The Energy Collective*, "Bakken shale gas flaring highlights global problem," <http://theenergycollective.com/geoffrey-styles/449241/bakken-shale-gas-flaring-highlights-global-problem>.

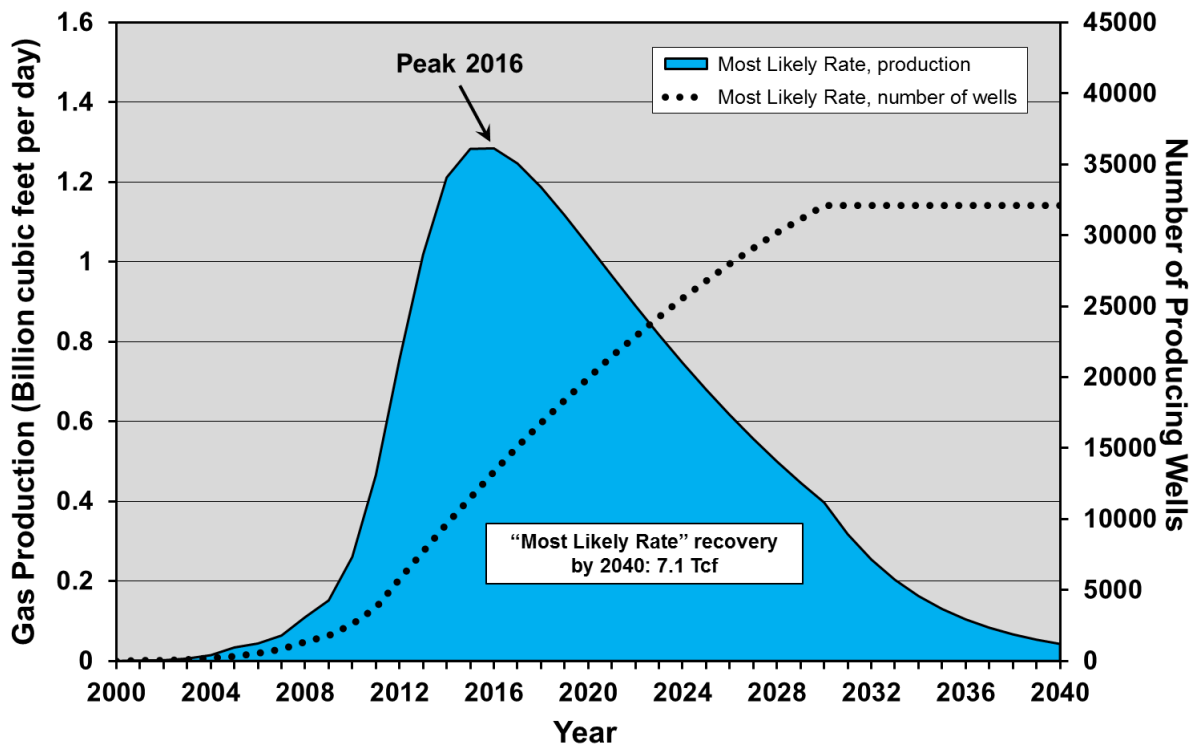
<sup>165</sup> Carroll, Joe, July 2014, *Bloomberg*, "Bakken Oil Explorers Told to Cut Flaring or Face Crude Caps," <http://www.bloomberg.com/news/2014-07-01/bakken-oil-explorers-told-to-cut-flaring-or-face-crude-caps-1-.html>.



### 3.4.2.2 Future Production Scenarios

Given that oil production is the driving force in the Bakken, and gas is a relatively small component of production, the “Most Likely” drilling rate scenario of the “Realistic Case” for oil production as outlined in Part 2 of this report is used for projection of future Bakken gas production. This scenario assumes that more than 32,000 wells will be drilled in total (compared to just over 8,500 wells at present), and that drilling will continue at current rates of 2,000 wells per year and gradually fall to 1,000 wells per year as the play is drilled off. It also assumes that well quality for gas production will decline from current levels as drilling moves from sweet spots for oil and gas into lower quality counties later in the play’s development.

Figure 3-112 illustrates the “Most Likely Rate” scenario for Bakken production (see Part 2 of this report for other key parameters used for this projection). Production is forecast to rise considerably from current levels to roughly 1.3 Bcf/d by 2016 before declining. Total gas recovery through 2040 will be about 7.1 Tcf, or nearly 7 times the amount produced from the play so far.



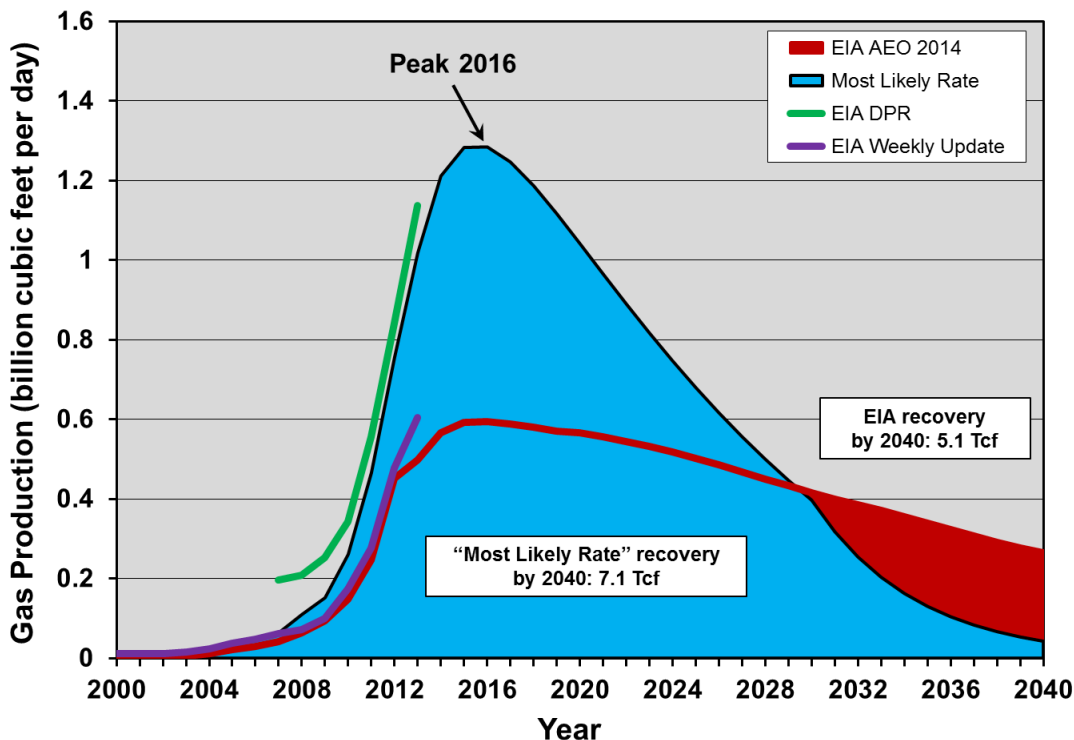
**Figure 3-112. “Most Likely Rate” scenario of Bakken gas production in the “Realistic Case” (80% of the remaining area is drillable at three wells per square mile).**

This projection assumes that well quality for gas production will parallel well quality trends for oil production as drilling moves into lower quality parts of the play.

### 3.4.2.3 Comparison to EIA Forecast

Figure 3-113 illustrates the comparison of the “Most Likely” drilling rate projection to the EIA’s reference case forecast. Several points are evident:

- The EIA is highly underestimating current production in the Bakken in its forecast and overestimating production later on, after 2030. The EIA’s near term forecast is invalidated by its own data as shown in Figure 3-113, which shows much higher current gas production.
- The EIA forecasts a recovery of just 5.1 Tcf over the 2000-2040 period, or 2.0 Tcf less than the “Most Likely Rate” scenario over the same period. However, it assumes production of 0.7 Tcf more gas after 2030. This is a result of the underestimates of current and short- to medium-term Bakken production.
- The EIA forecasts peak Bakken gas production at roughly the same time as this report (2016), albeit at production levels of less than half that of this report.



**Figure 3-113. EIA reference case for Bakken shale gas<sup>166</sup> vs. this report’s “Most Likely Rate” scenario of the “Realistic Case,” 2000 to 2040**

Also shown are the EIA’s Bakken gas production statistics from its *Drilling Productivity Report* and its *Natural Gas Weekly Update*,<sup>167</sup> which contradict the early years of its AEO 2014 forecast. The EIA forecast is made on a “dry gas” basis, whereas the “Most Likely Rate” scenario forecast is made on a “raw gas” basis.

<sup>166</sup> EIA, *Annual Energy Outlook 2014*.

<sup>167</sup> EIA, *Drilling Productivity Report*, retrieved October 2014, <http://www.eia.gov/petroleum/drilling>, EIA, *Natural Gas Weekly Update*, retrieved October 2014, <http://www.eia.gov/naturalgas/weekly>.



## 3.5 ALL-PLAYS ANALYSIS

The foregoing analysis of shale gas plays has reviewed 88% of estimated June 2014, shale gas production<sup>168</sup> and 88% of the cumulative shale gas production that is forecast in the EIA’s 2012-2040 reference case.<sup>169</sup> Although the EIA forecast for the Marcellus play is rated as “reasonable” and its forecast for the Bakken play is rated “conservative,” the deficit left by being “very highly optimistic” on some of the other plays makes finding and developing the gas required to meet the overall forecast highly to very highly optimistic.

This section will further explore the outlook for overall U.S. shale gas production with a summary analysis of the plays’ EIA forecasts, well quality, and production prospects to 2040.

### 3.5.1 Summary of EIA Forecasts

Table 3-6 summarizes the salient details of the EIA projections versus historical production and the EIA’s estimates of “unproved technically recoverable resources” and “proved reserves.”

Play	EIA Recovery 2012-2040 (Tcf)	Production to Date (Tcf)	EIA Unproved Resources as of January 1, 2012 (Tcf)	EIA Proved Reserves as of 2012 (Tcf)	Total Proved and Unproved Technically Recoverable (Tcf)	Percent of Unproved Resources and Proved Reserves Recovered by 2040 in EIA Forecast	Percent of Total Recovery in EIA Reference Case	EIA Production in 2040 (Tcf/year)	Optimism Bias
Barnett	44.4	15.60	20.3	23.7	44.0	101.0	10.1	2.15	Very High
Haynesville	97.2	9.41	70.9	17.7	88.6	109.8	22.0	3.37	Very High
Fayetteville	38.9	5.08	29.8	9.7	39.5	98.4	8.8	1.53	Very High
Woodford	22.8	3.14	16.8	11.1	27.9	81.6	5.2	0.82	High
Marcellus	127.2	9.70	118.9	42.8	161.7	78.7	28.8	4.57	Reasonable
Bakken	4.8	1.10	6.4	N/A	6.3	75.9	1.1	0.10	Conservative
Eagle Ford	56.7	3.90	60.3	16.2	76.5	74.2	12.8	2.70	Very High
Other	49.6	11.66	165.8	8.2	174.0	28.5	11.2	4.58	Unknown
Total	441.6	59.59	489.0	129.4	618.4	71.4	100.0	19.82	High to Very High

**Table 3-6. Comparison of EIA reference case shale gas forecast assumptions<sup>170</sup> with unproved technically recoverable resources<sup>171</sup> and proved reserves<sup>172</sup> to cumulative production from shale gas plays.<sup>173</sup>**

A determination of each play’s “optimism bias” is included. Numbers may not add due to rounding.

<sup>168</sup> EIA, *Natural Gas Weekly Update*, retrieved July 2014, [http://www.eia.gov/naturalgas/weekly/archive/2014/07\\_24/index.cfm](http://www.eia.gov/naturalgas/weekly/archive/2014/07_24/index.cfm).

<sup>169</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA. EIA, *Annual Energy Outlook 2014*, reference case forecast, Table 14, oil and gas supply, [http://www.eia.gov/forecasts/aeo/excel/aeotab\\_14.xlsx](http://www.eia.gov/forecasts/aeo/excel/aeotab_14.xlsx).

<sup>170</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>171</sup> EIA, *Assumptions to the Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

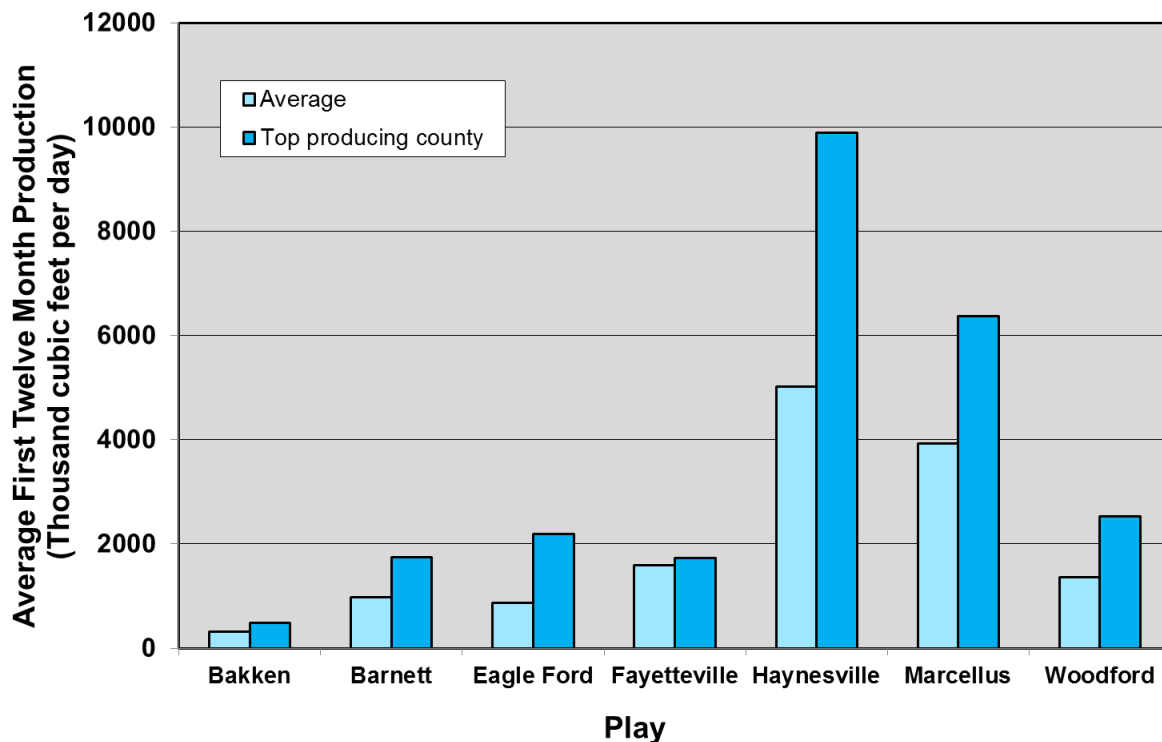
<sup>172</sup> EIA, <http://www.eia.gov/naturalgas/crudeoilreserves/index.cfm>.

<sup>173</sup> Data from Drillinginfo retrieved August to September 2014.

### 3.5.2 Well Quality

A comparison of plays analyzed in this report reveals that they are highly variable in terms of well quality and that the Marcellus and Haynesville stand out as clearly superior. The estimated ultimate recovery (EUR) of wells has been reviewed in the discussion of each play in this report, with the caveat that these are merely estimates and subject to change as more data emerge on longer-term well productivity.

Another measure for comparison of plays is the average first-year production from wells. This metric builds in the current geology and the cumulative impact of all technological innovations in drilling and completions to date if the most recent year is used. Figure 3-114 illustrates the average first-year production of horizontal wells in the seven plays analyzed in this study for 2013 for both the average of all wells in the play and the average for wells in the best county. Although the best play from this comparison is clearly the Haynesville, the Haynesville has a much higher field decline rate than the Marcellus which will tend to equalize the two over time. It is clear, however, that high quality shale gas plays are not ubiquitous, and even within the top producers there is considerable variation in average well quality.

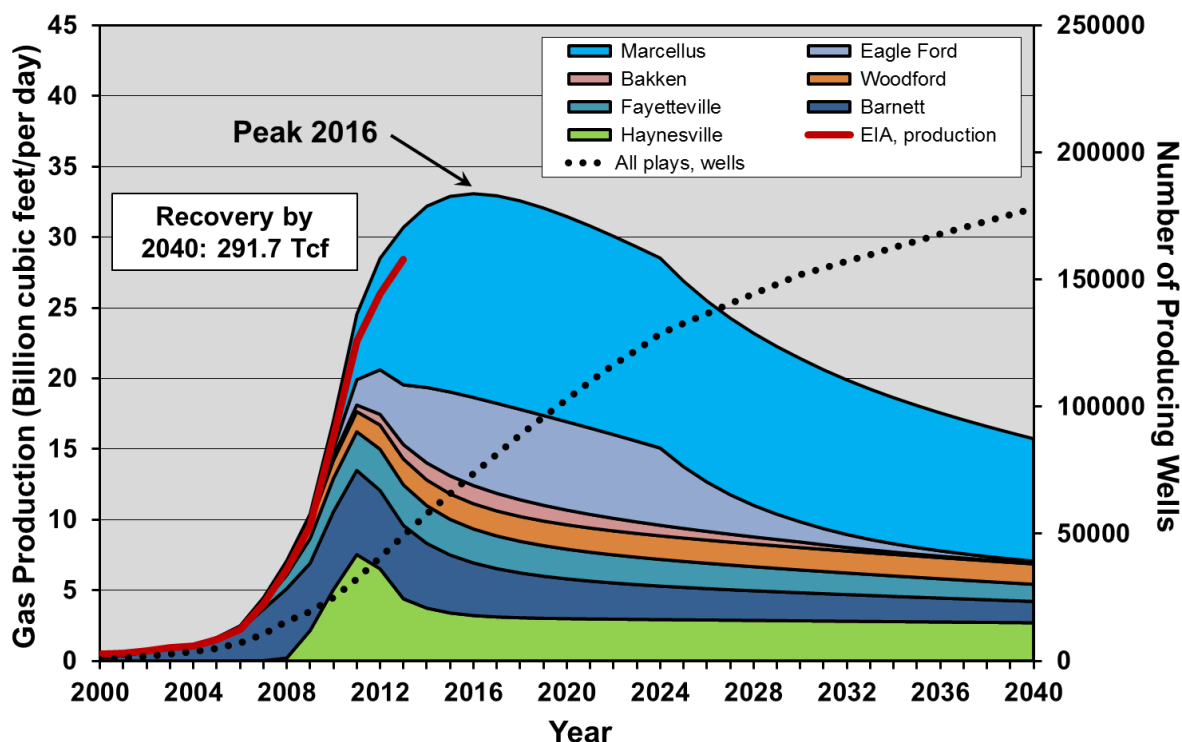


**Figure 3-114. Average first-year gas production per well in 2013 from horizontal wells both play-wide and in the top-producing county for the plays analyzed in this report.<sup>174</sup>**

<sup>174</sup> Data from Drillinginfo retrieved August to September 2014.

### 3.5.3 Production Through 2040

Figure 3-115 illustrates the sum of shale gas production from the plays analyzed in this report through 2040 in the “Most Likely” drilling rate scenario, along with the number of wells required to achieve it. Production from these plays peaks in 2016 at nearly 34 Bcf/d and declines to below 16 Bcf/d by 2040, or more than 50%. Total production over the 2000 to 2040 period is projected to be 291.7 trillion cubic feet. The Marcellus will make up 55% of production from these plays in 2040. Approximately 130,000 additional wells will need to be drilled by 2040 to meet the projections in Figure 3-115, on top of the 50,000 wells drilled in these plays through 2013. Assuming an average well cost of \$7 million, this would require \$910 billion of additional capital input by 2040, not including leasing, operating, and other ancillary costs.

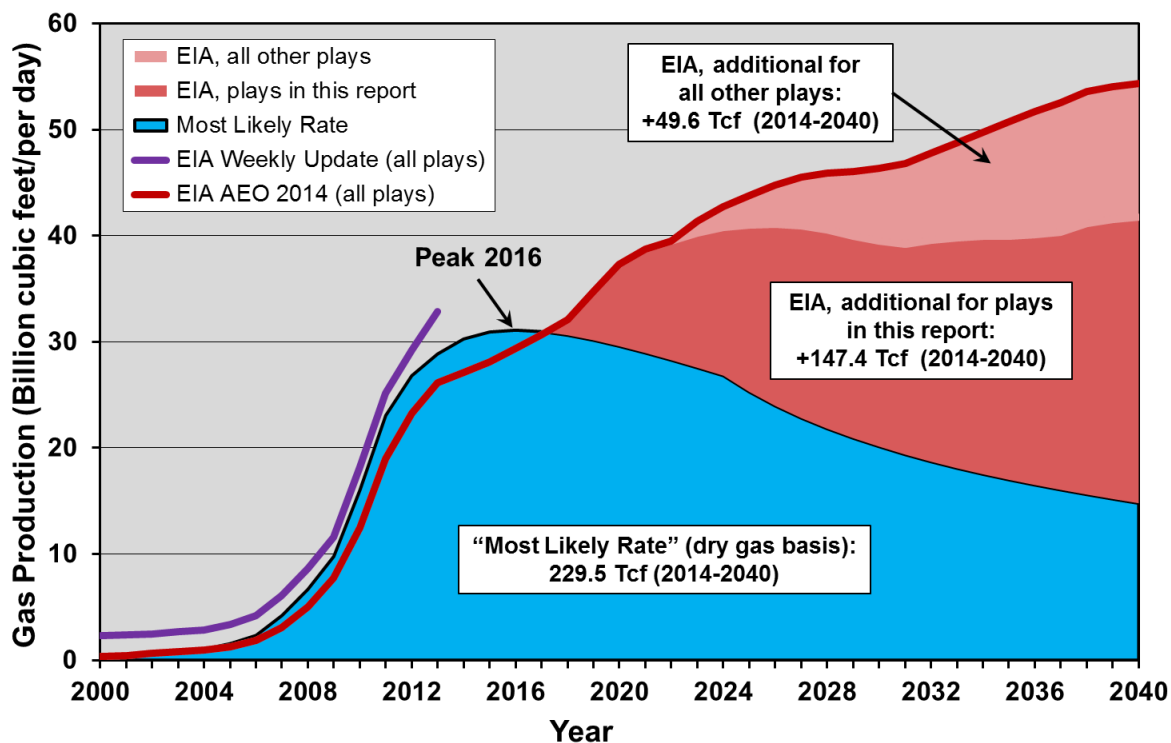


**Figure 3-115. “Most Likely Rate” scenarios for the seven shale gas plays analyzed in this report and number of producing wells, through 2040.**

The “Most Likely Rate” scenario projections here are made on a “raw gas” basis. 180,000 wells will be producing by 2040 in this scenario. Also shown is the EIA’s production data for dry gas through August 2014 for these plays.<sup>175</sup>

<sup>175</sup> EIA, *Natural Gas Weekly Update*, retrieved October 2014, <http://www.eia.gov/naturalgas/weekly>.

Figure 3-116 illustrates the EIA's reference case forecast for shale gas compared to the projections in this report for the seven plays analyzed. This comparison is made on a "dry" basis, given that the EIA forecast is for dry gas.<sup>176</sup> As can be seen, actual production of shale gas from these plays is higher in the near term than the EIA forecast and higher yet for the EIA's own independent estimate (from its *Natural Gas Weekly Update*) of actual shale gas production through August 2014. In the longer term, however, the EIA forecast overestimates production from the plays in this report's "Most Likely Rate" scenario through 2040 by 147.4 Tcf, or 64%. The EIA further estimates that in 2040, production from the plays analyzed in this report will be 182% higher (nearly 3 times) than estimated herein, and that by 2040, another 49.6 Tcf will have been recovered from other plays not analyzed in this report. Indeed, if the analysis in this report is correct, in order to meet the EIA reference case forecast other plays will have to recover an additional 198.2 Tcf—nearly 4 times the EIA's own estimate for other plays.



**Figure 3-116. Totaled "Most Likely Rate" scenarios for the seven shale gas plays analyzed in this report, compared to the EIA's reference case forecast for these plays and for all plays.<sup>177,178</sup>**

The "Most Likely Rate" scenario projections here are made on a "dry gas" basis. Also shown are the EIA's gas production statistics from its *Natural Gas Weekly Update*,<sup>179</sup> which contradict the early years of its AEO 2014 forecast.

<sup>176</sup> Dry gas has had liquids and other impurities removed and results in a shrinkage factor—in this case a shrinkage factor to dry basis is estimated at 6%, although the actual shrinkage factor varies by play and can be considerably higher for some plays—and lower for others.

<sup>177</sup> EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

<sup>178</sup> EIA, *Annual Energy Outlook 2014*, reference case forecast, Table 14, oil and gas supply, [http://www.eia.gov/forecasts/aeo/excel/aeotab\\_14.xlsx](http://www.eia.gov/forecasts/aeo/excel/aeotab_14.xlsx).

<sup>179</sup> EIA, *Natural Gas Weekly Update*, retrieved October 2014, <http://www.eia.gov/naturalgas/weekly>.

## 3.6 SUMMARY AND IMPLICATIONS

The growth of U.S. shale gas production has been a game-changer in a natural gas supply picture that as recently as 2005 was thought to be in terminal decline. The assumption that natural gas will be cheap and abundant for the foreseeable future has prompted fuel switching from coal to gas, along with investment in new generation and gas distribution infrastructure, investment in new North American manufacturing infrastructure, and calls for exporting the shale gas bounty to higher-priced markets in Europe and Asia.

Given these assumptions—and the investments being made and planned because of them—it is important to understand the long-term supply limitations of U.S. shale gas. The analysis presented herein, which is based on one of the best commercial databases of well production information available,<sup>180</sup> finds that the continued growth in supply over the long term at low prices is highly questionable. Certainly production will rise in the short term, but with the likely collective peaking of the seven major plays analyzed in this report (which provide 88% of current and estimated long-term U.S. shale gas output) in the 2016-2017 timeframe, maintaining production or even stemming the decline will require maintenance of high drilling rates, along with the capital input to sustain them.

This report finds that major shale plays are variable in well quality, with some plays—like the Marcellus and Haynesville—being much more productive on average than the rest. Furthermore, the assessment of individual counties within plays reveals that well quality varies considerably, and that the best counties are attracting most of the drilling and investment—meaning that the poorer-quality counties, which account for most of the remaining drilling locations, will be drilled last. Given that field declines are steep, requiring 25-50% of production to be replaced each year, the levels of drilling and capital investment needed to maintain production will escalate going forward. Without the considerably higher prices needed to justify drilling in poorer quality rock, production will fall. The concept that high-quality shale gas plays are widespread is false, along with the concept that they are “manufacturing operations”, where tens of thousands of wells can be drilled with the same productivity.

The EIA, which is viewed as perhaps the most authoritative source of U.S. energy production forecasts, has often overestimated future oil and gas production.<sup>181</sup> The analysis presented herein suggests that this is the case with respect to shale gas. A play-by-play analysis of the data with respect to the EIA forecasts reveals a high to very high “optimism bias” for most plays. The EIA assumes that 74% to 110% of its “unproved technically recoverable resources as of January 1, 2012” plus “proved reserves” will be recovered by 2040 for most plays. Unproved resources have no price constraints applied and are loosely constrained, compared to “reserves” which are proven to be recoverable with existing technology and economic conditions. Not only do the EIA’s projections demonstrate a high or very high optimism bias, they also assume that the U.S. will exit 2040 with shale gas production significantly higher than today, at 54.3 Bcf/d. This is highly unlikely given a thorough analysis of the data.

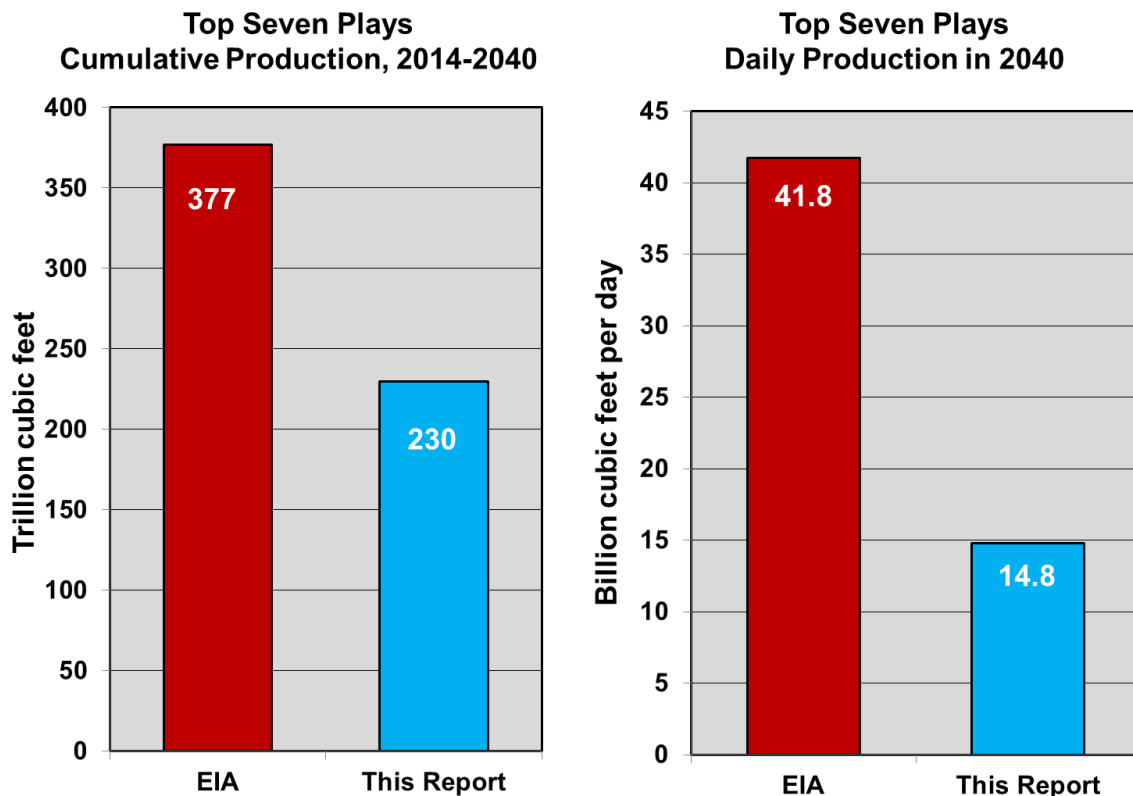
The major shale plays analyzed in this report have produced just under 45 trillion cubic feet through 2013, and will certainly continue to produce more gas. This report projects that they will produce an additional 230 trillion cubic feet over the 2014-2040 period, with production of 14.8 Bcf/d in 2040, given unconstrained capital input and no restrictions in access to drilling locations. In contrast, the EIA forecasts 377 trillion cubic feet of gas will be recovered from the plays analyzed in this report over this period, and that production will be nearly three times as high in 2040 at 41.8 Bcf/d. Figure 3-117 illustrates the stark difference between the EIA’s projections and this report’s projections for the seven major shale gas plays analyzed.

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<sup>180</sup> DI Desktop (formerly HDPI), produced by Drillinginfo.

<sup>181</sup> Hughes, J.D., 2013, *Drill Baby Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?*, Post Carbon Institute, <http://www.postcarbon.org/publications/drill-baby-drill>.





**Figure 3-117. Projected cumulative gas production to 2040 and daily gas production in 2040, EIA projection<sup>182</sup> versus this report’s projection.**

The values given here are for the seven plays analyzed in this report. These plays constitute 88% of cumulative U.S. shale gas production from 2014 to 2040 in the EIA’s reference case forecast.

The EIA’s forecast strains credibility, given the known decline rates, well quality by area, available drilling locations, and the number of wells that would need to be drilled to make the forecast a reality. Given this report’s “Most Likely” scenario estimate for the seven major plays analyzed, the remaining significant U.S. shale gas plays would need to produce 198.2 trillion cubic feet, or nearly 4 times the EIA’s own estimate for “other” plays, by 2040. Failing to do this would jeopardize many current and future investments made on the assumption of a cheap, abundant, and long-term domestic gas supply. Most troubling from an energy security point of view is that much of the shale gas production will occur in the early years of this period, when decisions about long-term investment in exports and domestic infrastructure are being made—making any supply constraints later even more problematic.

The consequences of getting it wrong on future shale gas production are immense. The EIA projects that the U.S. will be a significant LNG exporter in 2040 (15% of total production—see Figure 3-2). Although the flush of shale gas production is likely to peak by 2020 and decline thereafter, there are 4 approved, 13 proposed, and 13 potential<sup>183</sup> LNG export facilities under consideration. The wisdom of liquidating as quickly as possible what will likely turn out to be a short-term bonanza should be questioned. A sensible energy policy would be based on this prospect.

<sup>182</sup> EIA, *Annual Energy Outlook 2014*, <http://www.eia.gov/forecasts/aeo>.

<sup>183</sup> FERC, September 30, 2014, “Approved LNG terminals,” <http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf>; “Proposed LNG terminals,” <http://www.ferc.gov/industries/gas/indus-act/lng/lng-export-proposed.pdf>; “Potential LNG terminals,” <http://www.ferc.gov/industries/gas/indus-act/lng/lng-export-potential.pdf>.