Well Production Profiles for the Fayetteville Shale Gas Play

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Abstract

This article investigates well production profiles for the Fayetteville shale gas play. Well production profiles are constructed with monthly data. The well production profiles provide estimates for the following indicators: peak month production rates for the first year of well operation; total first year well production rates; first year well production decline rates; and inter-annual well production decline rates. The well production profiles are then used to construct an "average well" to estimate ultimate gas recovery for a forty year well production life. In conclusion, the "average well" profile is employed to project the scale of well development required to maintain an annual shale gas production rate of 500 billion cubic feet for forty years.

Introduction

Well production profiles for the Fayetteville shale gas play in north-central Arkansas are explored in this article. The information builds on our limited knowledge of shale gas production. The Fayetteville play is one of earliest shale gas plays to be developed with horizontal drilling. Hence, a well production profile for the October 2005 to September 2010 production period will help inform expectations for other emerging shale gas plays.

Four well production profiles are presented: peak month production rates for the first year of well operation; total first year well production rates; first year well production decline rates; and inter-annual well production decline rates for the first four years of well operation. The well production profiles are then used to construct an "average well" to estimate ultimate gas recovery for a forty year well production life. In conclusion, the "average well" profile is employed to project the scale of well development required to maintain an annual shale gas production level of 500 billion cubic feet (bcf) for forty years, which is believed informative since the findings for 500 bcf/year can easily be scaled to any annual shale gas production level.

The Fayetteville play covers 9,000 square miles and has technically recoverable gas resources of 41-58 trillion cubic feet (tcf) [1, 2]. For practical purposes, development of the play began in 2005 with the introduction of horizontal drilling. From 2005 to the present, annual growth in gas production has been impressive. Annual gas production levels are presented in Fig. 1.

The Fayetteville play produced 520 bcf of gas in 2009 and is on pace through the first nine months of 2010 to produce 750 bcf of gas. In 2009, the Fayetteville play was second in shale gas production to the Barnett play, which produced 1.75 tcf of gas [3]. The gas produced in these two plays accounts for about 10% of total U.S. natural gas production.

Obviously the growth in gas production is a direct result of the large expansion in the number of new wells brought into production each year. Annual new well counts are presented in Fig. 2. The number of new wells for the first nine months of 2010 is on pace to exceed the number of new wells in 2009.

Well Production Profiles

A well production analysis is performed with a data base compiled by the Arkansas Oil and Gas Commission [4]. The data base contains monthly gas sales data for 2,840 wells brought into production through September 2010. It is assumed that well sales volume is synonymous with well production volume.

To insure that all wells analyzed have at least one complete year of production, only wells with an initial production entry no later than October 2009 are included. Thirty-six wells are excluded because of data issues. In the interest of analyzing horizontal wells, wells brought into production prior to October 2005 are excluded because it is believed that the mix of these wells is weighted toward vertical wells. With these data constraints, the following well production profiles are based on the following number of wells with complete annual data: 1,933 wells with one year of production; 1,033 wells with two years of production; 836 wells with three years of production; and 69 wells with four years of production.

While gas production rates for individual wells are heterogeneous, which is readily observed in the graphs for five wells presented in Fig. 3, there are similarities. The four-year well production histories show a peak in gas production in the first couple of months with a steep production decline in the following months. Also, notice that well production decline rates begin to stabilize at a relatively low level in the fourth year.

A significant number of wells report multiple months of zero production, which primarily is caused by shut-in periods for development of nearby wells and subsequent reservoir re-pressuring. Some of the zero production months may be the result of temporary pipeline constraints. Also, in Fig. 3 observe that months with low or zero production levels are sometimes followed with marked improvements in well performance, which is attributable to the frac of an offset well.

Peak month production in the first year of well operation is the first well production profile. This is a commonly reported metric to assess well quality. The average well peak month production level is 1.85 million cubic feet per day (mmcf/d). Over the four year observation period, the average peak month production increases from 1.35 mmcf/d to 2.2 mmcf/d. The distribution of wells by peak month production levels is presented in Fig. 4. Sixty-one percent of wells have a peak month production less than 2.0 mmcf/d and thirty-nine percent have a peak month production greater than 2.0 mmcf/d.

The next well production profile is average gas production for the first year of well operation. This is an important metric since horizontal shale gas wells produce approximately 25% of their EUR (expected ultimate recovery) in the first year. The average first year production rate is 1.12 mmcf/d, which is equivalent to 410 mmcf/year. The distribution of average first year well production rates are presented in Fig. 5. Notice that the average first year well production rate has increased 121% from the 2005-2006 production year to the 2009-2010 production year. This finding indicates significant learning curve gains in field exploration and drilling.

The first year well production averages include many wells that may be considered dry or non-economic. In Fig. 6, I present the percentage of wells by first year production totals. If it is assumed that an economic well has a minimum first year production of 200 to 250 mmcf, then 20% to 30% of the wells completed in the Fayetteville play are not economic. However, based on the finding that first year well production rates have increased dramatically the past couple of years, it should be expected that the percentage of non-economic wells will decline significantly over time.

A caveat is the possibility that the increase in well production rates is due to identification and focus on core production areas. The Fayetteville core areas are presented in Fig. 7. If true that a concentration on high production core areas is the cause of increasing well productivity, then the question becomes whether once development of core areas is exhausted the percentage distribution of well productivity in Fig. 6 becomes replicated in the long-term.

The next well production profile is the average well production decline rate in the first year of production. The first year production decline rate is based on the decrease from peak month production to twelfth month production. The average first year well production decline rate is 56%. The distribution of first year well production decline rates is presented in Fig. 8. Fifty percent of the well decline rates are greater than the average and fifty percent are less than the average.

The annual distribution of average first year well production decline rates range from 53% to 60% over the four year observation period. This implies a relatively stable average well decline rate. Also, it is worth noting that the average first year well production decline rate of 56% for the Fayetteville play is compatible with first year decline rates reported for the Barnett play [5].

A final well production profile is average inter-annual well production decline rates. Inter-annual decline rates are based on the decline in average annual well production rates that occur from one year to the next. The average inter-annual well production decline rates are: 55% from Year 1 to Year 2; 41% from Year 2 to Year 3; and 28% from Year 3 to Year 4. With these average inter-annual well production decline rates, the average first year well production rate of 1.12 mmcf/d is expected to decline to 0.51 mmcf/d in the second year, 0.30 mmcf/d in the third year, and 0.21 mmcf/d in the fourth year. In should be noted that the inter-annual decline rate is not the same as the intra-annual well production decline rate, which is based on the well production decline that occurs from the peak month in a given year to the twelfth month.

An "Average Well" Profile

I conclude by modeling an "average well" with a forty year production history. The modeling parameters for the "average well" are the average well production profiles presented above. Because of the brief history of horizontal shale gas drilling, well production decline rates for Years 5-40 are unknown. It is assumed that the average long-term inter-annual production decline rates are: 14% for Year 5; 10% for Years 6-8; 8% for Year 9; and 6% for Years 10-40. The long-term inter-annual decline rate projections are derived from the assignment of a constant 0.83% monthly well production decline rate for each month in Years 5-40. The resulting 6% terminal inter-annual decline rate is consistent with expectations stated by a SEECO (Southwestern Energy) representative.

The forty year estimated ultimate recovery (EUR) for the "average well" is 1.7 bcf. A graph of the "average well" forty year production history is presented in Fig. 9. Well production rates are: 805 mcf/d in the twelfth month of the first year; 112 mcf/d at the end of the tenth year; 60 mcf/d at the end of the twentieth year; 33 mcf/d at the end of the thirtieth year; and 18 mcf/d at the end of the fortieth year.

The "average well" produces about 25% of its EUR in the first year, 50% in the fifth year, and 66% in the tenth year. After twenty years, cumulative gas produced is 1.4 bcf, which is 85% of the well's EUR. It is interesting that an additional twenty years of well production, Years 21-40, contributes only 15% to a well's forty year EUR.

The forty-year "average well" gas production profile is now applied to a projection of well development required to maintain a constant 500 bcf/year gas production rate. This is important because of the annual decline rates for shale gas wells. The purpose is to provide an approximate metric to help inform the scale of annual drilling activity required to sustain a constant level of shale gas production over time.

The annual and cumulative number of "average wells" required to maintain a 500 bcf/year gas production rate is presented in Fig. 10. The number of wells to produce 500 bcf of gas in the first year of production is 1,220. The number of new well additions to compensate for declines in existing well production ranges from 670 new wells in Year 2 and declines annually to 285 new wells in Years 18-40. The cumulative number of wells to maintain a 500 bcf/year gas production rate for forty years is 14,549.

In conclusion, the usefulness of the "average well" concept needs to take into account the long-term effect of well infilling (down-spacing) and refracing on long-term well production rates. Well down-spacing decreases the spacing of wells from the current practice of 80-160 acres per well to 10-40 acres per well. Well down-spacing increases the recovery factor of gas in place for a given development acreage, but comes at the expense of reducing the ultimate recovery of individual wells within the development area. Also, well refracing will likely occur in high production areas and alter well production profiles. Halliburton estimates that infilling and refracing will increase the recovery of total gas-in-place from about 11% to 18% [5].

References

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3. Texas Railroad Commission. 2010. Barnett shale gas production. Texas Railroad Commission, Austin, Texas.

4. Arkansas Oil and Gas Commission. 2010. Fayetteville Shale Gas Sales, Individual Well Gas Sales – Cumulative Total by Monthly. Arkansas Oil and Gas Commission, Little Rock, Arkansas.

5. Halliburton. 2008. US Shale Gas – An Unconventional Resource, Unconventional Challenge. Halliburton white paper, 2008.

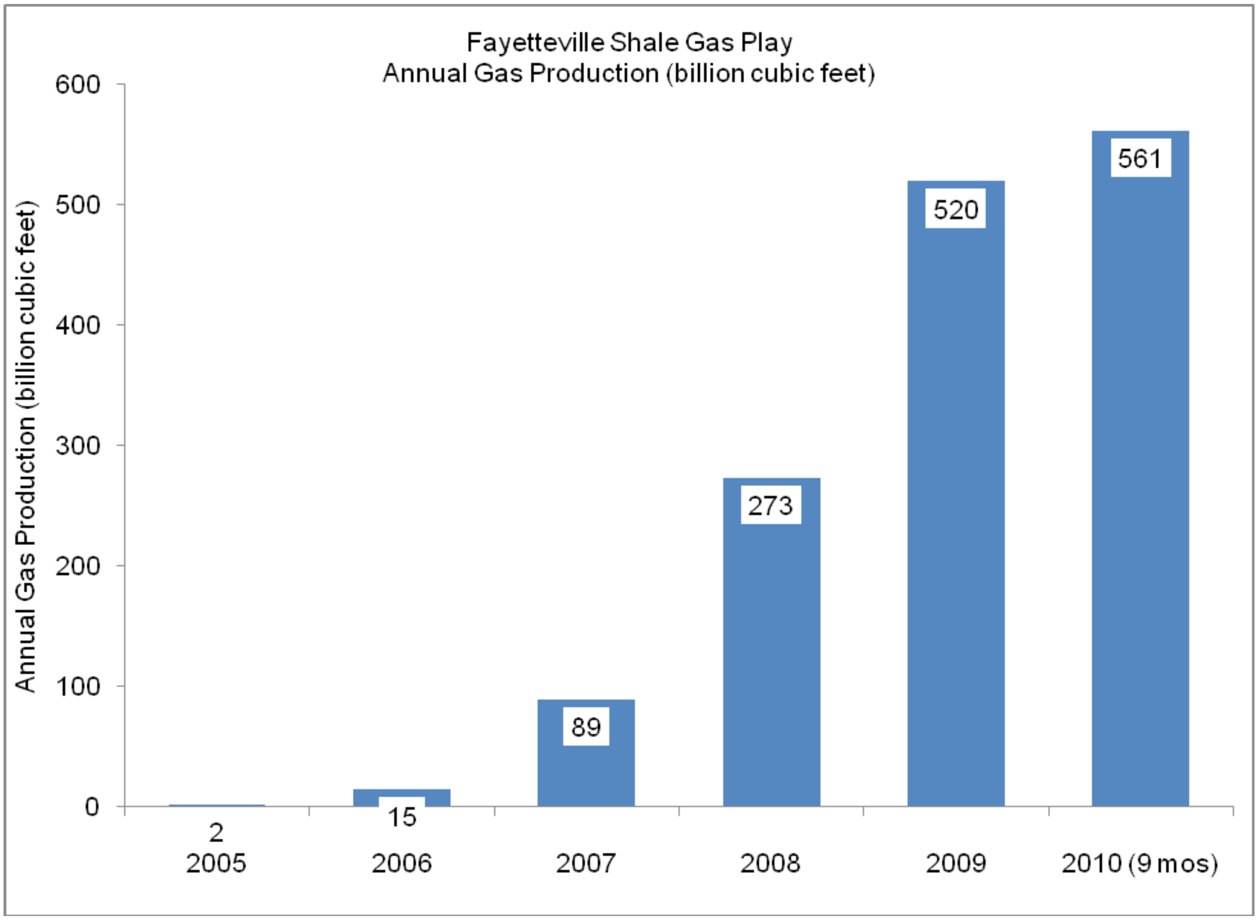

Figure 1. Annual gas production for Fayetteville Shale Gas Play.

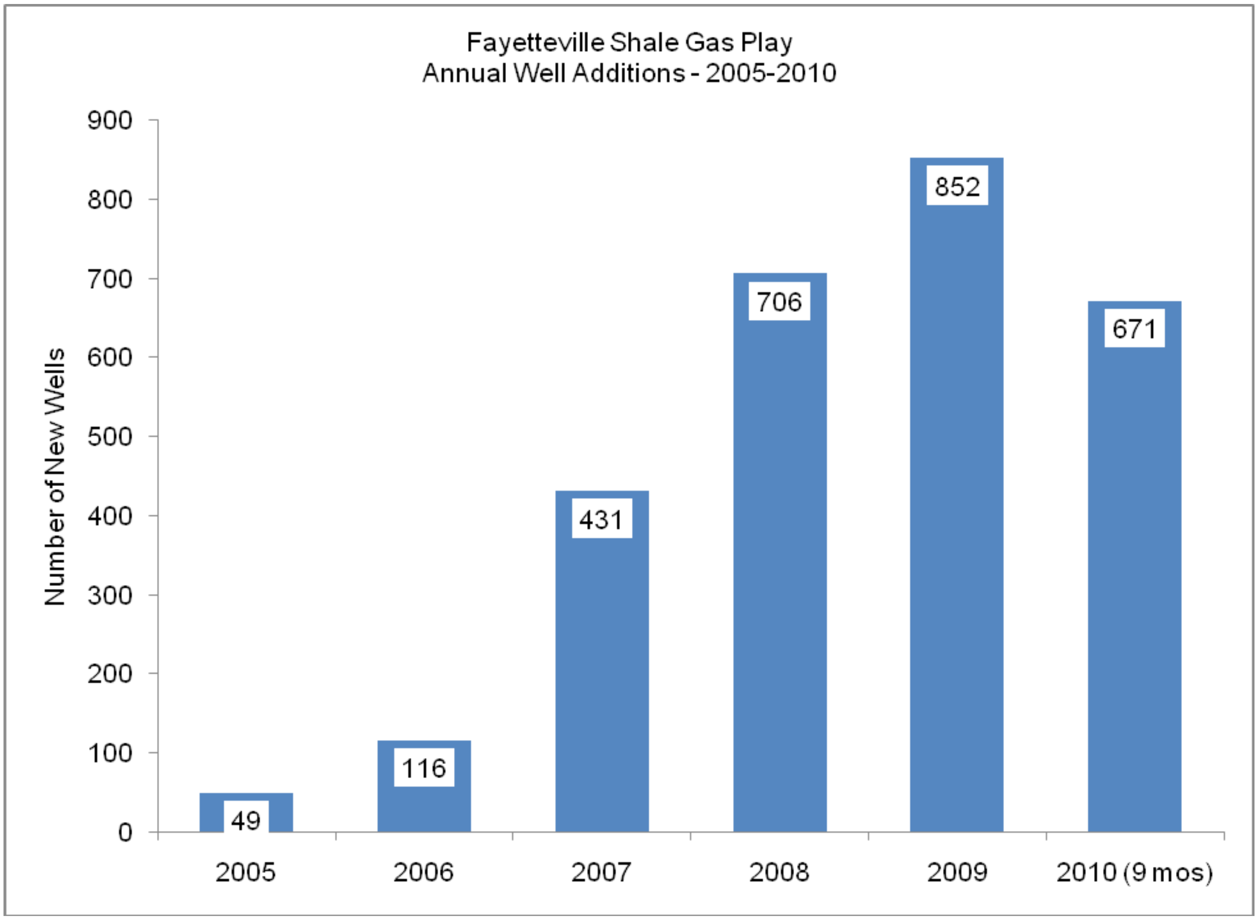

Figure 2. Number of well completions in the Fatteville shale gas play, January 2005 through September 2010.

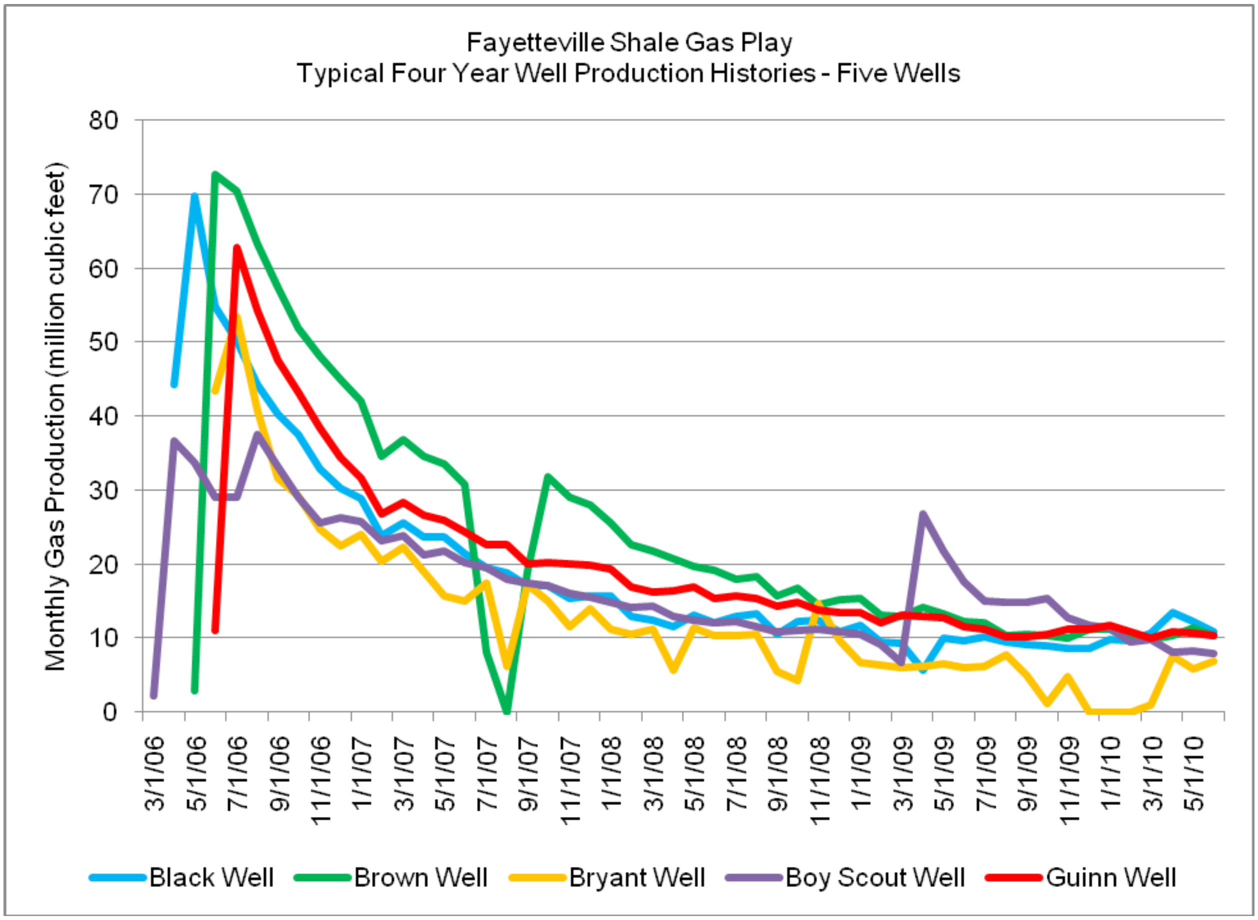

Figure 3. Four year gas production histories for five relatively high production gas wells in the Fayetteville shale gas play.

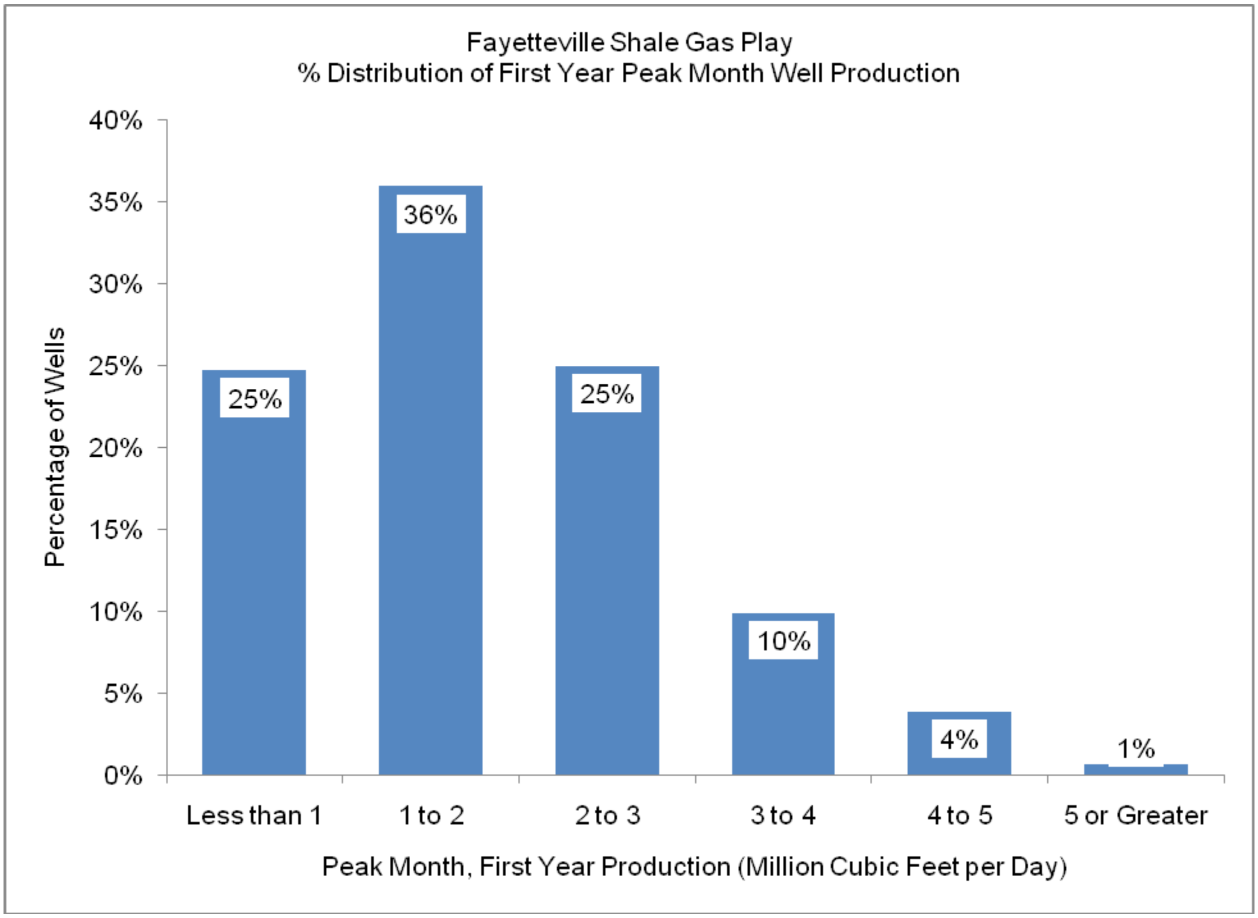

Figure 4. Distribution of first year, peak month well production from October 2005 through September 2010.

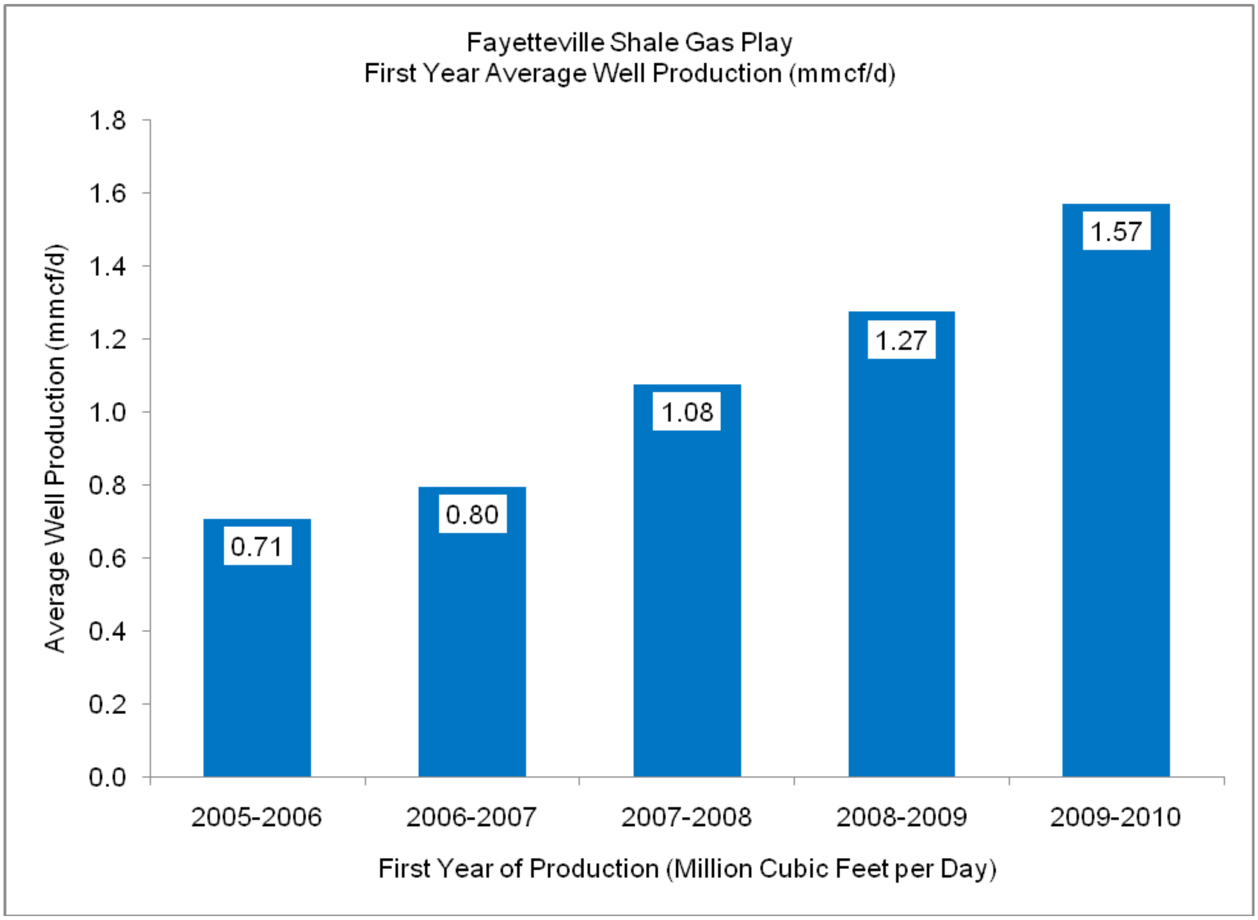

Figure 5. First year average well production rates reported as million cubic feet per day (mmcf/d). The column labels in the graph represent average first year well production rates based on October to September production because data reports are through September 2010.

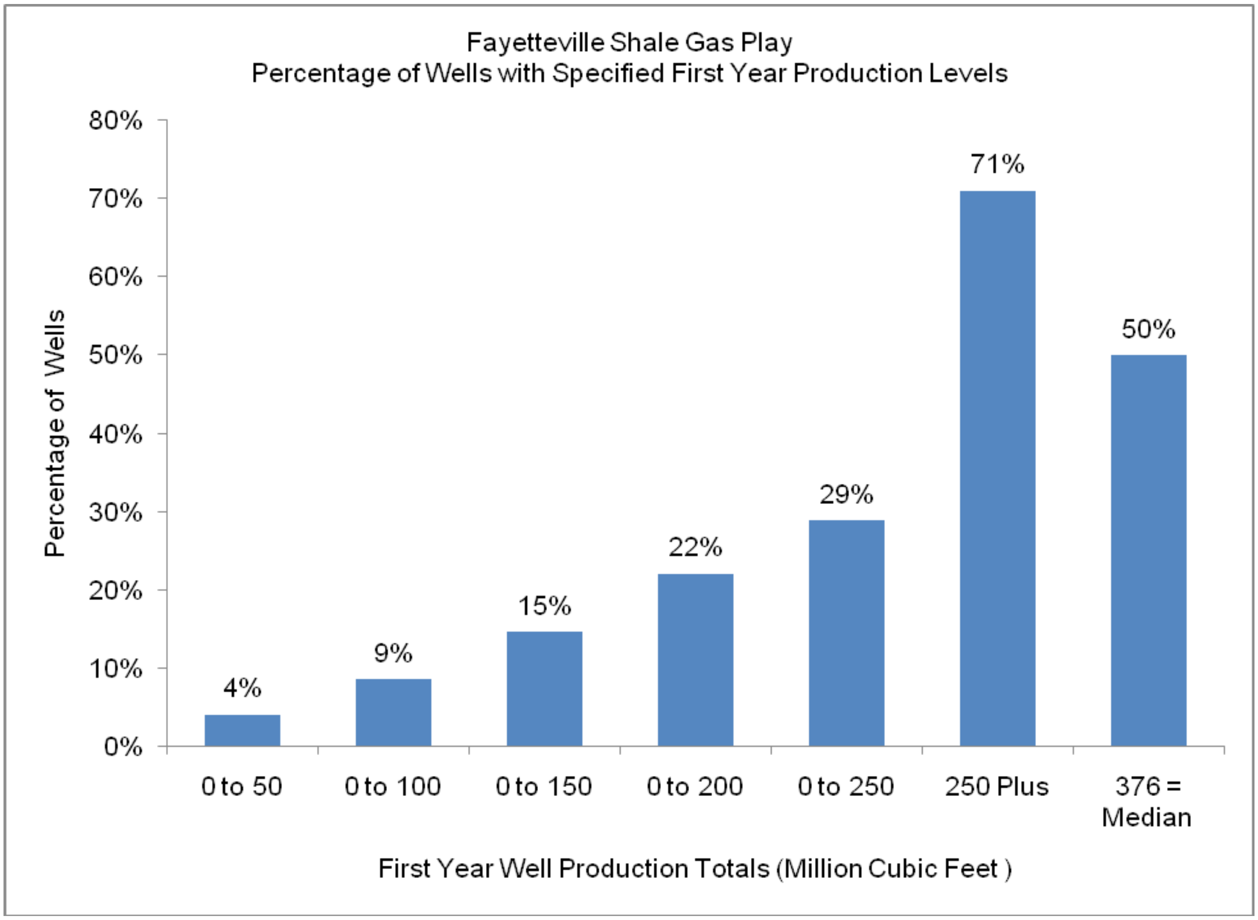

Figure 6. Percentage distribution of first year well production totals.

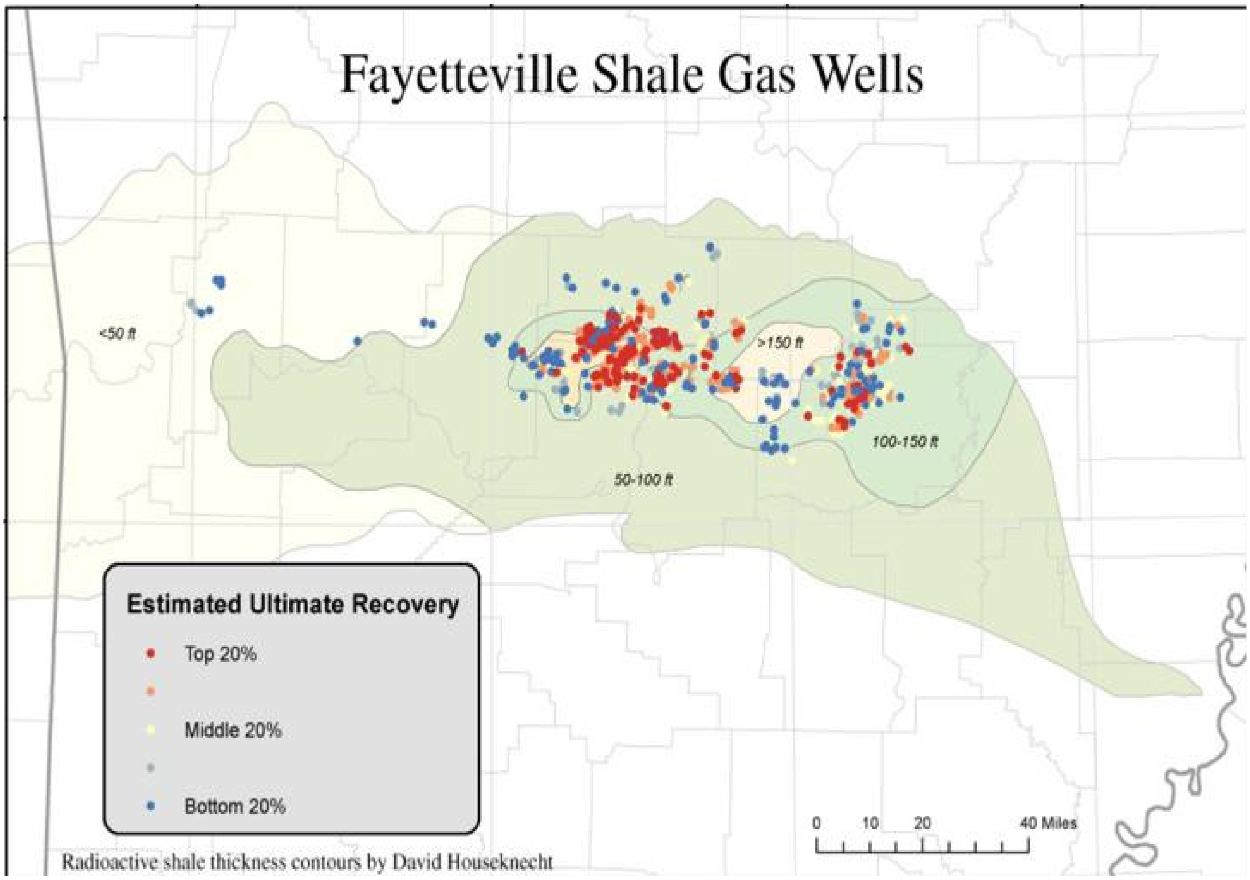

Figure 7. United States Geological Survey (USGS) map of well production in the Fayetteville shale gas play (2010).

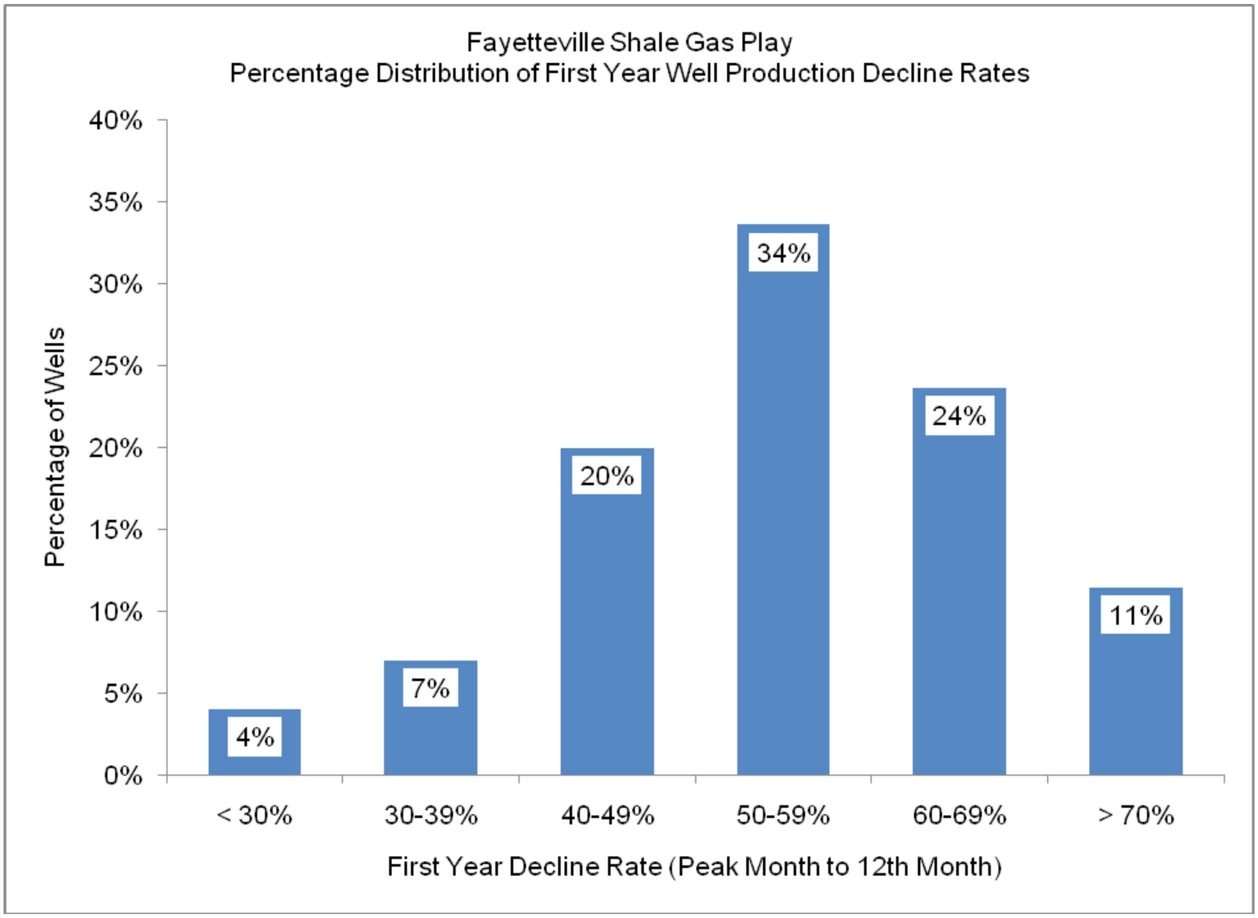

Figure 8. Percentage distribution of first year well production decline rates. The average well production decline rate is 56% with 50% of wells above 56% and 50% below.

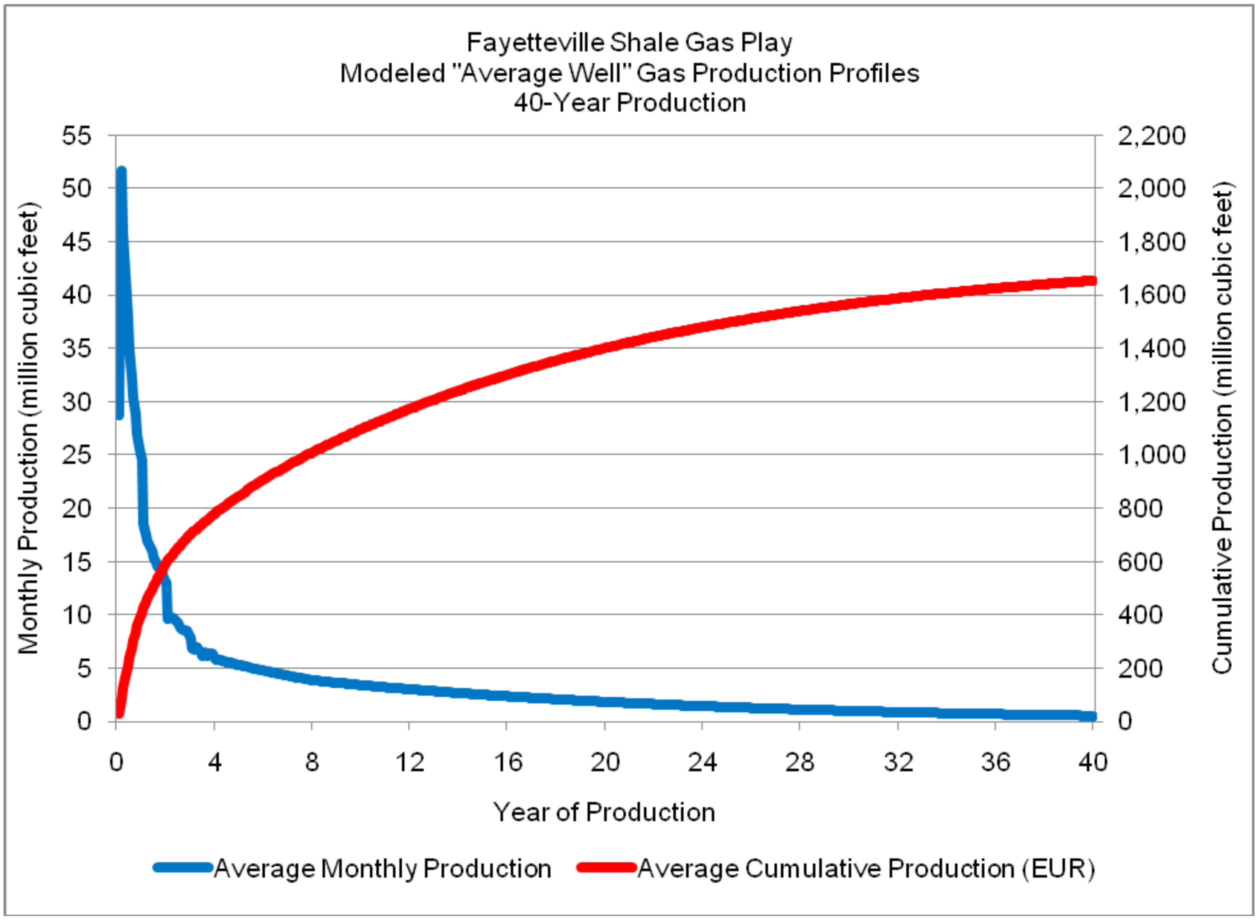

Figure 9. Average monthly and cumulative gas production projections for the "average well" in the Fayetteville shale gas play.

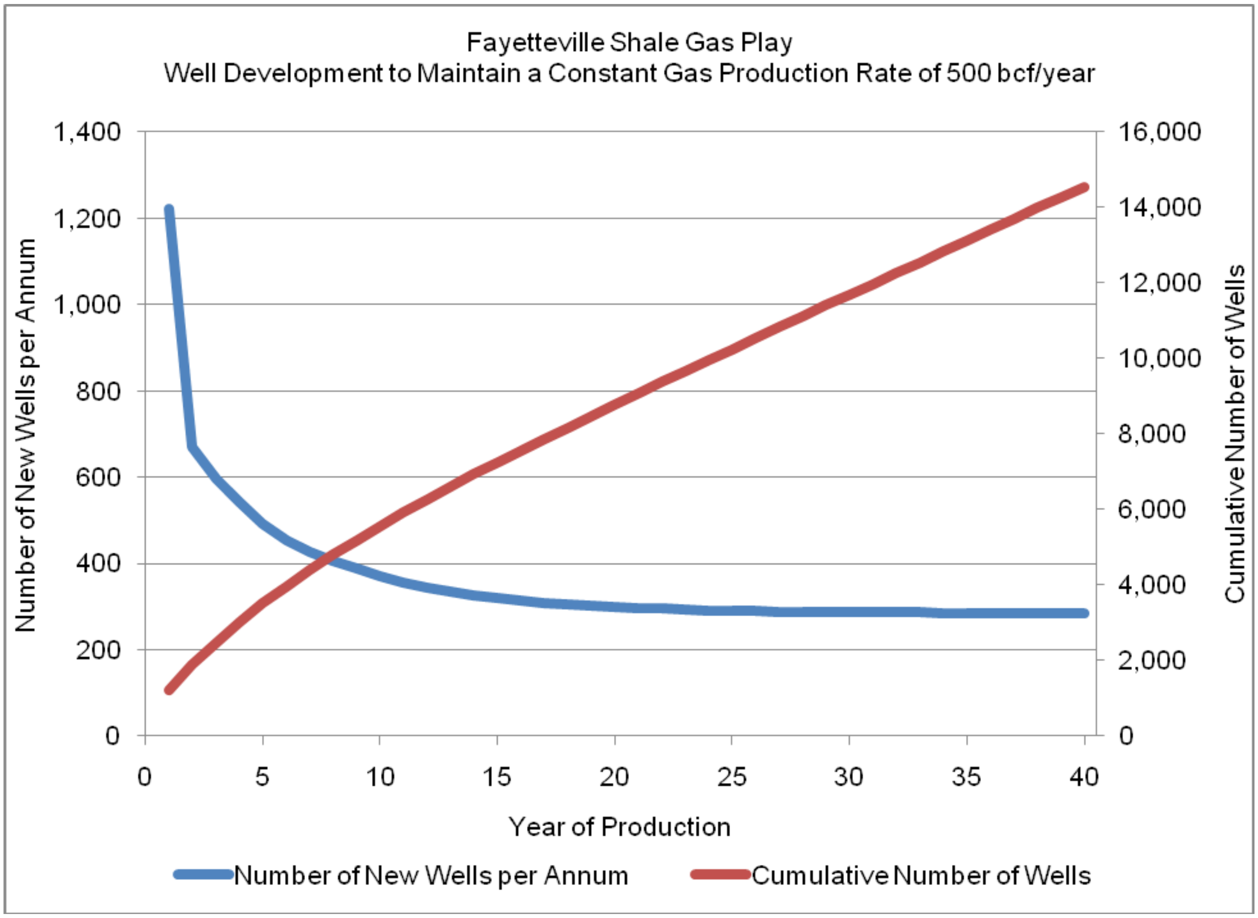

Figure 10. Annual new well development, assuming "average well" production, to maintain a constant gas production rate of 0.5 tcf/year over a forty year gas production period.