Well Production Profiles for the Fayetteville Shale Gas Play Revisited

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Biographical Sketch – James Mason
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This article is an update of "Well Production Profiles for the Fayetteville Shale Gas Play," which appeared in OGJ April 4, 2011. The article reported an average well production profile with a 1.7 Bcf EUR. The average well production profile was generated by averaging multi-year, October 2005-September 2010, well production data. Reporting an averaged, multi-year well production profile was criticized for understating average well production profiles based on recent advances in well production technology. The criticism is deemed valid. In this article, average well production profiles are reported for each of the years 2008 through 2011.

Also, the Energy Information Administration's (EIA) U.S. shale gas technically recoverable resource (TRR) estimates are being debated. This article reviews and evaluates the 2011 EIA Fayetteville shale gas TRR estimate [1]. The shale gas well production analyses in this article are performed with monthly well production data from the Arkansas Oil and Gas Commission (AOGC) [2]. Additional information is from E&P company presentations [3, 4, 5, 6].

The Fayetteville Shale lies within the Arkoma Basin and covers 9,000 square miles as shown in Fig. 1. The Fayetteville Shale is segmented into a 4,000 sq. mi. eastern area and a 5,000 sq. mi. western area. Shale gas exploration and production is focused on the eastern core area.

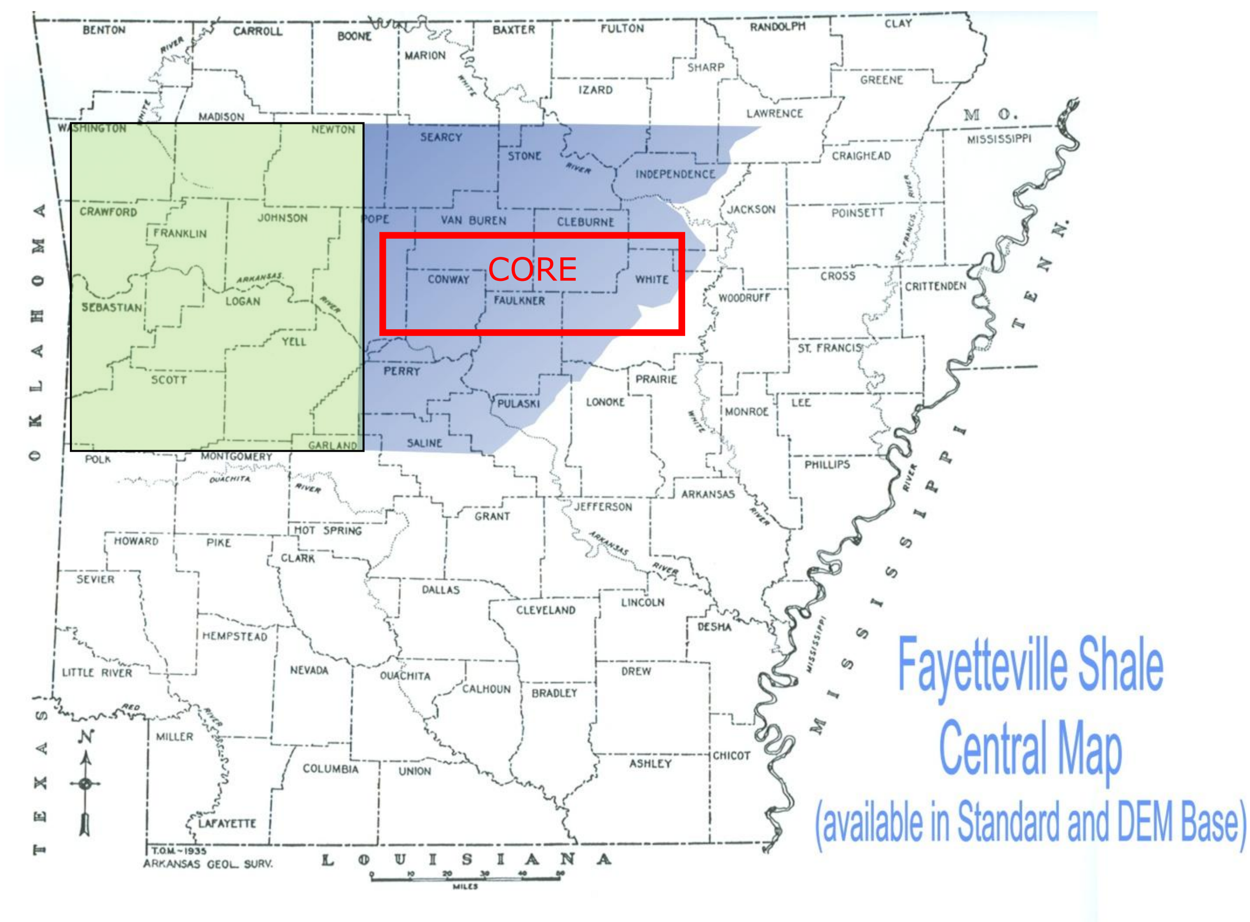

Figure 1. Fayetteville Shale Play – the Blue eastern area is the primary shale gas exploration and production area, and the core production area is outlined in red (edited AOGC map).

The Fayetteville Shale is a dry gas play and does not produce natural gas liquids or petroleum. The 2011 EIA shale gas TRR estimate for the Fayetteville Shale is 32 Tcf [1]. An overview of the EIA Fayetteville Shale TRR estimate is given in Table 1.

Table 1. Overview EIA Fayetteville Shale Estimates.[a]

	Eastern Area	Western Area
Total Area (square miles)	4,000	5,000
Well Development Area (square miles)[b]	1,518	504
EUR (Bcf/well)	2.25	1.15
Well Spacing (wells/sq. mi.)	8	8
TRR (Tcf)	27.32	4.64

Notes:

a. Abbreviations: EUR = estimated ultimate recovery (wells); TRR = technically recoverable resource (plays); Bcf = billion cubic feet; and Tcf = trillion cubic feet.
b. Well development area is TRR divided by the product of well spacing and well EUR.

Three E&P companies account for 99% of the well activity in the Fayetteville Shale– Southwestern Energy's subsidiary SEECO, ExxonMobil's subsidiary XTO Energy, and BHP Billiton Petroleum. Southwestern Energy's subsidiary SEECO is the first mover in the Fayetteville Shale and reports lease rights to 800,000 net acres in the eastern area and 125,000 net acres in the western area [3]. In 2010, ExxonMobil bought XTO Energy and purchased Petrohawk Energy's Fayetteville Shale holdings to bring its total Fayetteville Shale lease rights to 560,000 net acres [4]. In 2011, BHP Billiton Petroleum purchased Chesapeake Energy's Fayetteville Shale holdings and reports lease rights to 500,000 net acres [5].

The net acreage of lease rights in the eastern portion of the Fayetteville Shale is about 1.9 million net acres or about 3,000 square miles. From the EIA estimates in Table 1, to achieve the 27.32 Tcf TRR will require well development of about 50% of the net acreage with existing lease rights. Also, the average well EUR needs to be 2.25 Bcf with well spacing of 8 wells per square mile. The drainage area of a sample well to achieve a 80 acre well spacing, which is equivalent to 8 wells per square mile (640 acres = 1 square mile), is presented in Fig. 2. The feasibility of these assumptions is evaluated with well production data and E&P company information.

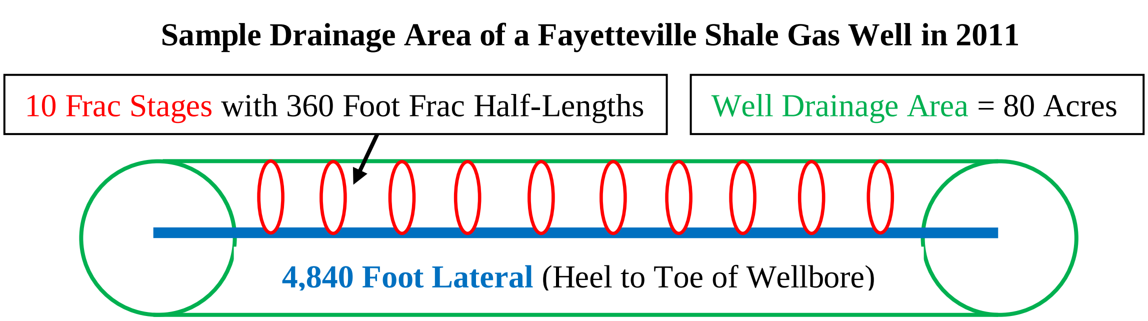

Figure 2. Sample characteristics of well drainage area to achieve 80 acre well spacing.

Shale gas production with advanced horizontal well hydraulic fracturing technology is still in the learning curve stage of development. Two important trends in the Fayetteville Shale are a reduction in well drilling time, which decreases well completion cost and drilling longer laterals, which enables more frac stages and an increase in well production. According to Southwestern Energy, average drilling time in 2011 was 8 days and well lateral lengths have almost doubled from 2007-2011 – from an average of 2,657 feet in 2007 to an average of 4,836 feet in 2011, and drilling costs have decreased from $3.0 million in 2008 to $2.8 million in 2011 [3, 6].

The additional expense of drilling longer laterals and performing more and larger frac stages only makes sense if there are positive financial returns. E&P companies report that the increased costs associated with drilling longer laterals and performing more and larger frac stages is being offset by reductions in well drilling costs and increases in well production rates. Attention is now turned well production analyses 2008-2011.

The following well production analyses are based on well data through December 2011 from the State of Arkansas Oil and Gas Commission's Fayetteville Shale B-43 well database, which provides a complete listing of monthly natural gas sales for each producing well [2]. The initial production (IP) rate used in this analysis is the first "full" month of production, which is the second month of reported well production. The production for the first reported month is most likely not a full month of production since a well can begin production on any day of the month.

In 2011, the number of well completions in the Fayetteville Shale was 848, which are 41 less than in 2010. Well completion totals for 2008-2011 are presented in Fig. 3. SEECO and XTO

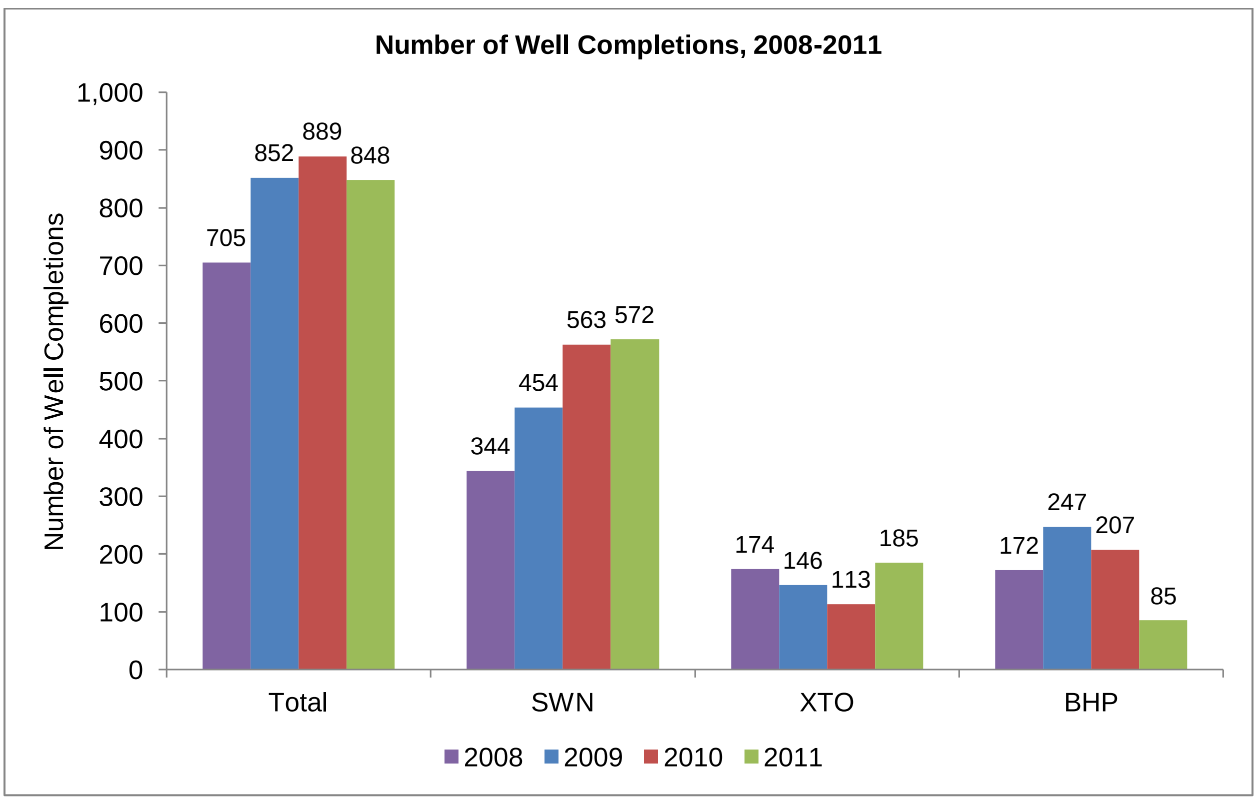

Figure 3. Number of well completions, 2009-2011.

increased the number of well completions in 2011, while BHP significantly reduced the number of well completions. The decrease in BHP well completions is possibly a consequence of the transition process as BHP takes control of Chesapeake Energy's Fayetteville Shale holdings.

The 2011 well completion totals indicate that the pace of well development in the Fayetteville Shale is slowing. This is not surprising in lieu of low natural gas prices and well development demands in other more recent shale gas plays such as the Marcellus Shale. Natural gas prices declined throughout 2011 and monthly well completions are investigated to check if this had an impact on the rate of well completions over the course of 2011. Monthly well completion totals for 2010 and 2011 are presented in Fig. 4. Comparison of monthly well completion totals does not show evidence of a reduction in the rate of well completions over the course of 2011.

In annual reports, E&P companies state that hedged natural gas price positions enable aggressive well development in dry gas plays. Projections of low natural gas prices for 2012-2013 and reductions in hedge/contract prices indicate a reduction is dry gas well development in 2012 and going forward until natural gas prices rise to acceptable levels. For example, Southwestern Energy plans to reduce the number of well completions in the Fayetteville Shale in 2012 to 420-430 operated wells, which is 25% less than their 2011 well completions [3]. With the planned reduction in number of 2012 well completions, Southwestern Energy's projection of 2012 Fayetteville natural gas production is approximately 6% greater than 2011 production [3].

The 2011 Fayetteville Shale natural gas production total is 943 Bcf, which is 21% greater than 2010 production. Annual natural gas production totals for the Fayetteville Shale are presented in Fig. 5. It will be interesting to see if 2012 production tops the 1.0 Tcf mark with possible curtailment in well development.

There has been a large increase in average well production since horizontal well hydraulic fracturing technology was introduced to the Fayetteville Shale in 2005. In the April 4, 2011 OGJ article, the reported average well production profile has a 1.7 Bcf EUR. As previously noted, the average well production profile was generated by averaging well production totals from October 2005 through September 2010. This is not an accurate representation of current expected average well production since multi-year averaging washes out the effects of advances in well production technology.

This article presents four well production profiles for wells completed in each of the years 2008 through 2011. This approach demonstrates the progression in well performance that is being realized with well designs incorporating longer laterals and more frac stages. A comparison of first year average well performance for wells completed 2008-2011 is presented in Fig. 6.

The results in Fig. 6 show significant increases in first year average well performance. Notice that the incremental increases decline each year and that the 2012 first year average well performance is basically the same as that in 2011. This suggests possible identification of an optimal well design for the Fayetteville Shale.

The first year average monthly well production totals are for wells completed from January through December in each of the years, which means that there is not complete twelve month

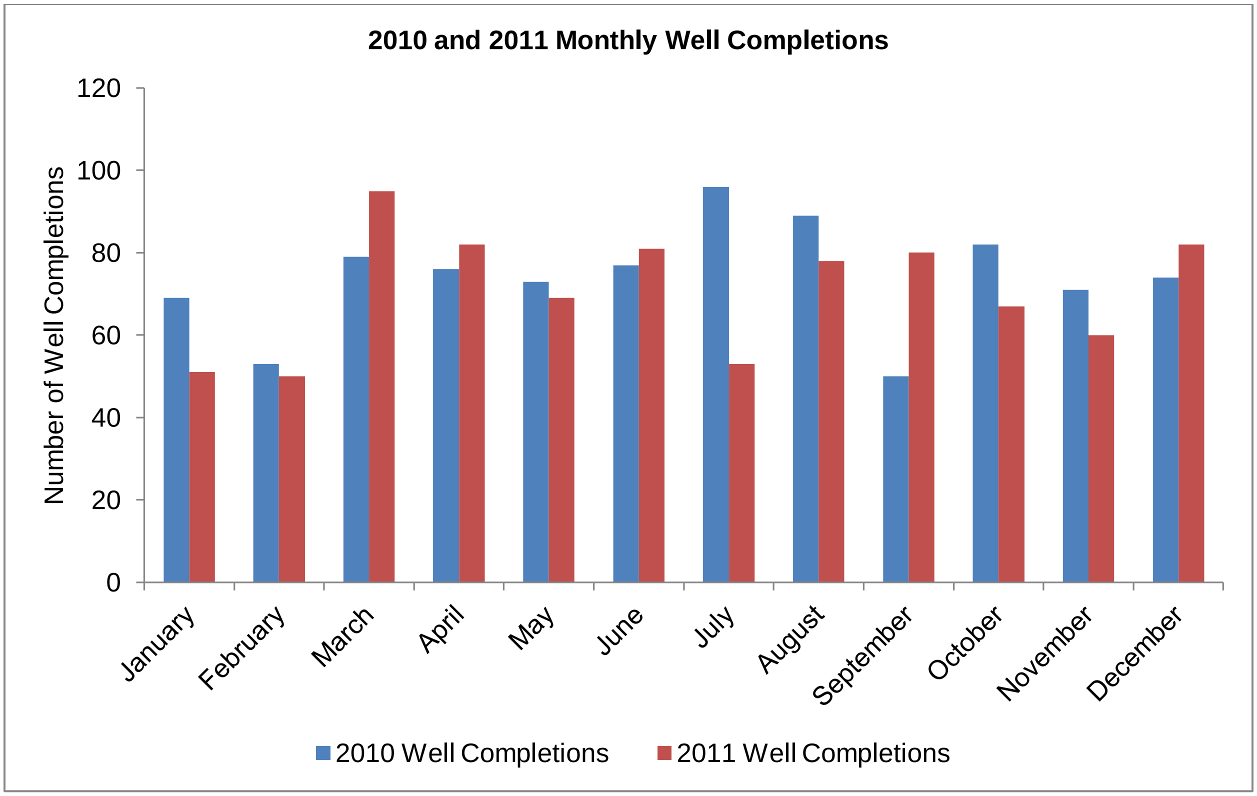

Figure 4. 2010 and 2011 monthly well completions.

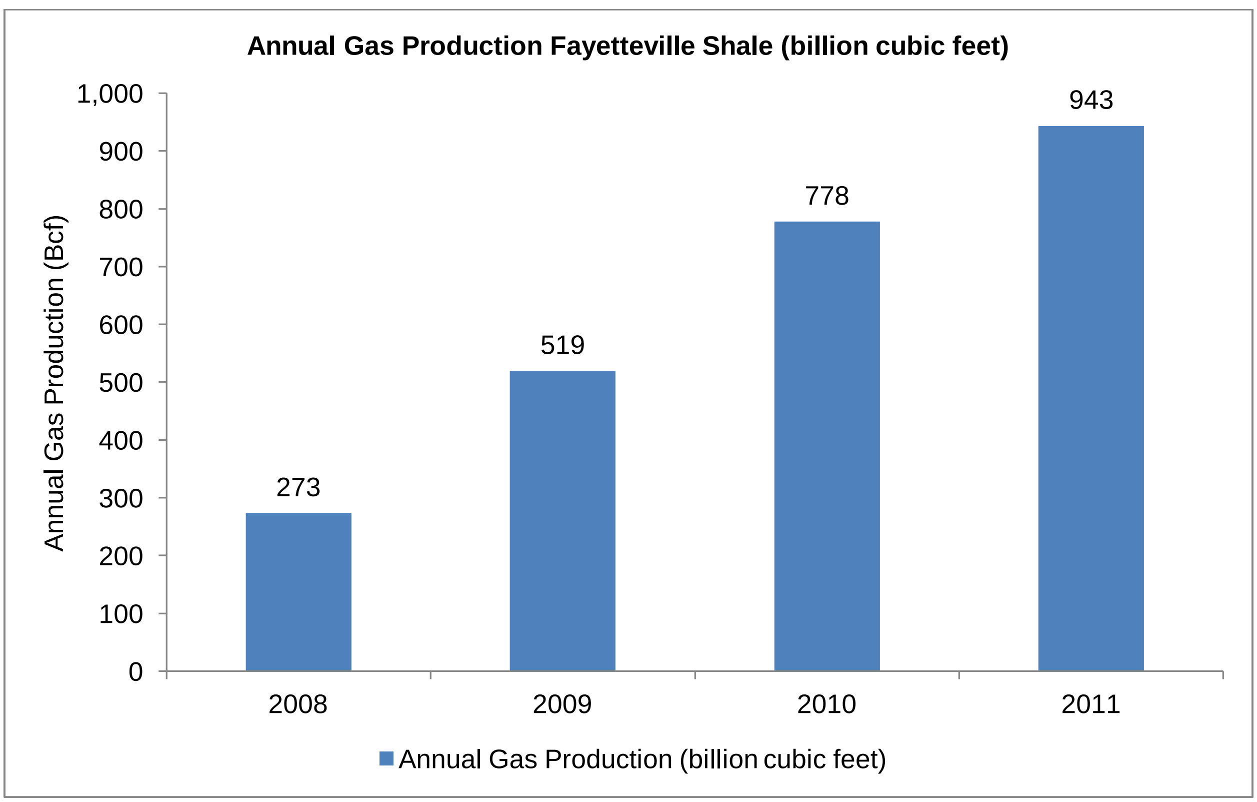

Figure 5. Fayetteville shale gas production, 2009-2010.

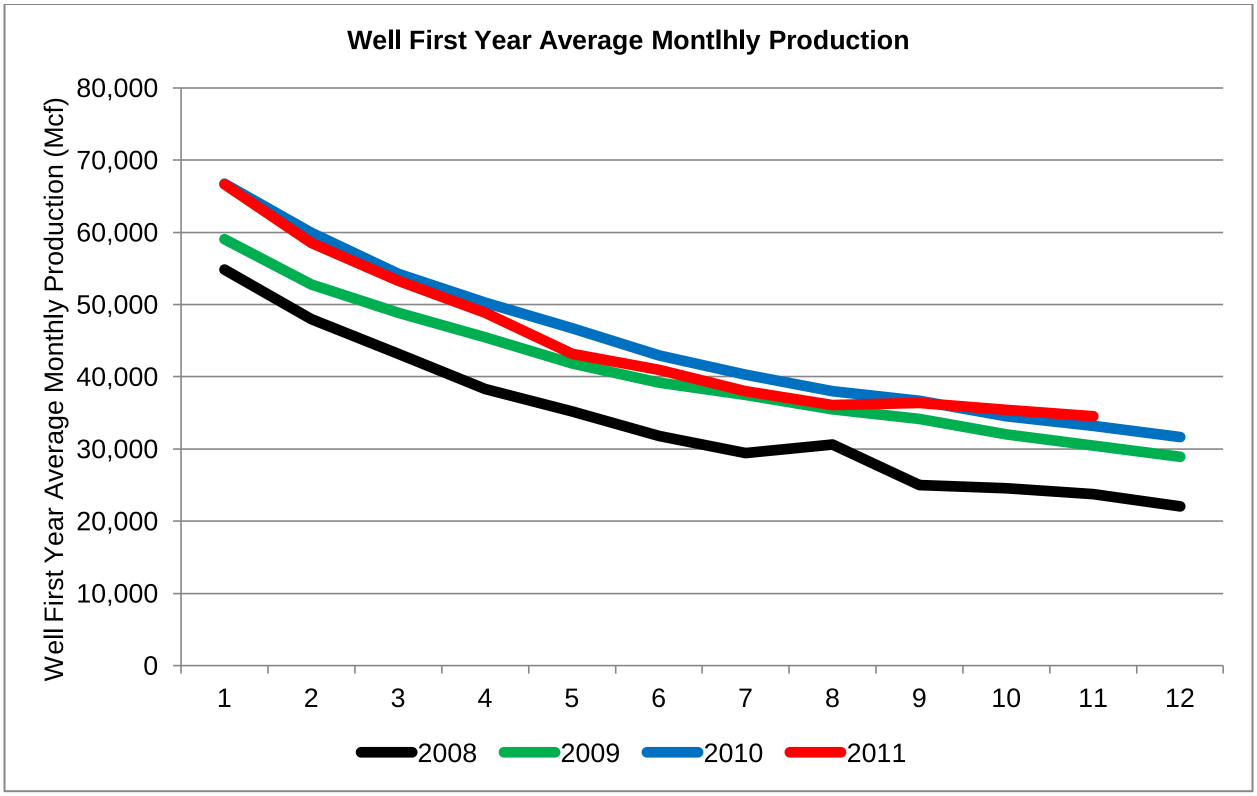

Figure 6. Well first year average monthly production (thousand cubic feet).

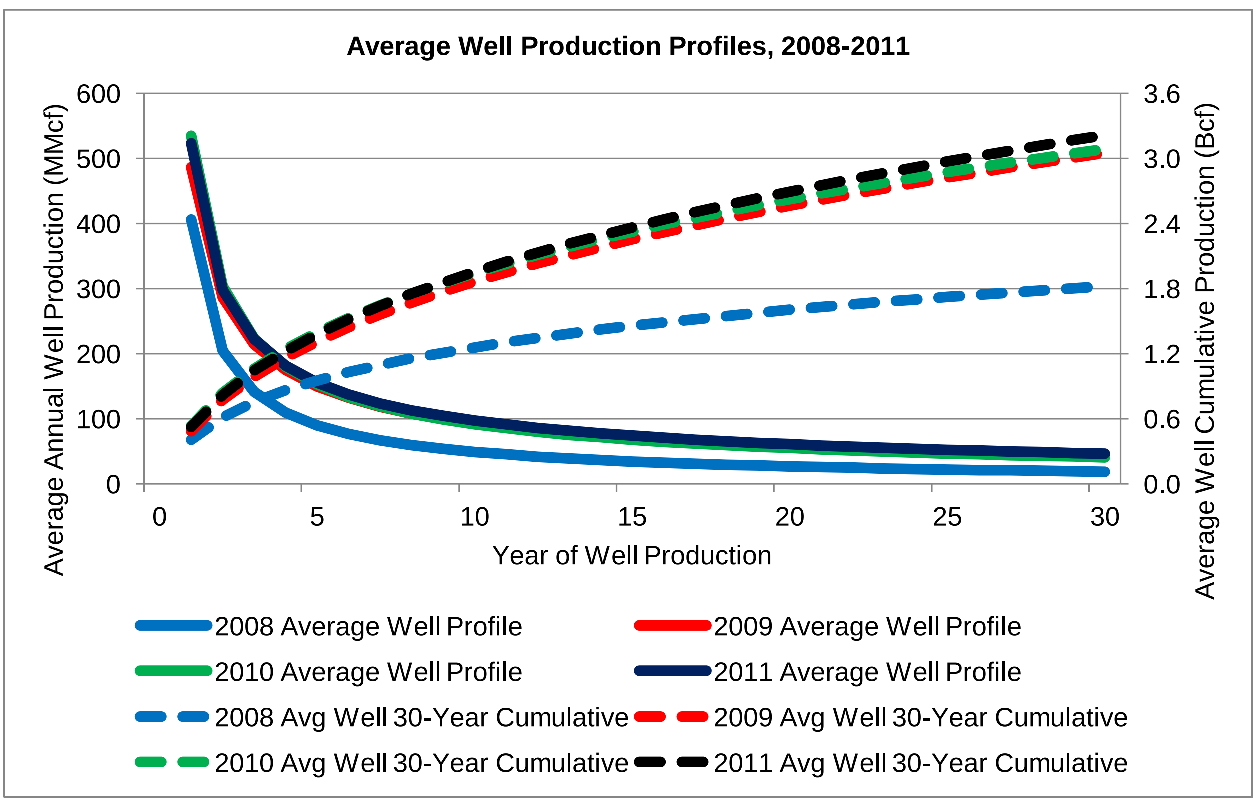

Figure 7. Average Well Production Profiles, 2008-2011.

data for all wells completed in 2011. For example, the wells completed in January 2011 will not have twelve full months of production until January 2012. In other words, each month over the course of 2011 has a fewer number of wells generating the average monthly totals. Hence, the 2011 average well production totals should be interpreted as preliminary findings.

As reported in the 2011 OGJ article, there is wide variation in individual well performance. It goes without saying that shale gas drilling involves risk. While some wells may be dry holes, it is the average well performance over a portfolio of wells that matters. The booking of proven reserves is based on expected average well EUR's (estimated ultimate recovery). It is important to recognize that average well EUR's change over time due to factors such as advances in technology and changes in the gas production properties of well development acreage.

To investigate the effect of recent technology advances on well EUR's, average well EUR's are calculated for wells completed in 2008, 2009, 2010, and 2011. The average well EUR's assume a thirty-year well production life and are derived by fitting a hyperbolic curve to the actual first year average well production curves that are shown in Fig. 6. The hyperbolic curve formula is:

Hyperbolic Curve Formula: $q_t = q_i / (1 + b D_i t)^{1/b}$,

where q_t = production in month t

q_{ip}= initial production (first full-month production)

b = decline exponent

D_i = nominal decline rate

t = time in month of production.

The decline exponent, b, and the nominal decline rate, D_i, are unknowns and are estimated by minimizing the squared differences between the formula fitted data points and the actual well production data points. The minimization routine searches for the b and D_i values that generate a best fitting curve to the actual first year average well production data, and the results are then extrapolated to generate a thirty-year average well production profile.

The thirty-year average well production profile findings are presented in Fig. 7 and Table 2. The average well EUR estimates increase from 1.8 Bcf for wells completed in 2008 to 3.2 Bcf for

Table 2. Fayetteville Average Well Production Profiles, 2008-2011.

	2008	2009	2010	2011
IP (MMcf)	54.86	59.08	66.75	66.64
Decline Exponent (b)	1.15	1.45	1.36	1.50
Nominal Decline Rate (Di)	0.14	0.11	0.12	0.13
EUR (Bcf)	1.82	3.05	3.09	3.21
EUR Sensitivity to Changes in Annual Decline Rate:				
EUR with a Constant 6% Decline Rate Years 13-30 (Bcf)	1.79	2.90	2.96	3.05
EUR Reduction with a Constant 6% Decline Rate	2%	5%	4%	5%
EUR with a Constant 10% Decline Rate Years 8-30 (Bcf)	1.66	2.58	2.66	2.70
EUR Reduction with a Constant 6% Decline Rate	9%	16%	14%	16%

wells completed in 2011. The 3.2 Bcf average well EUR for 2011 wells is consistent with BHP's reported Fayetteville Shale average well EUR [5]. Notice that there is only a 5% difference in the average well EUR's between the 2009 and 2011 estimates, which is another indication of a well design plateau being reached in terms of optimizing well production in the Fayetteville Shale. Once again it should be noted that the 2011 findings are preliminary.

Since annual natural gas production for the Fayetteville Shale is approaching 1.0 Tcf, it is of interest to evaluate the well count necessary to maintain an annual 1.0 Tcf natural gas production rate for thirty years. Because well production declines over time, new wells have to be brought into production to maintain a constant annual production level. For the 2010 average well production profile with a 3.1 Bcf EUR, it takes 1,869 wells to initiate an annual 1.0 Tcf gas production level, and the cumulative number of wells to maintain this annual production level for thirty years is 12,188 wells. The annual and cumulative well counts are presented in Fig. 8.

There is controversy regarding E&P company representation of average well EUR's and the way long-term well production decline rates are modeled, which has an impact on reserve bookings. The controversy resulted in investigations by the Securities Exchange Commission and State of New York Attorney General's Office in 2011. Determination of long-term well production decline rates is problematic because of the short history for horizontal hydraulic fracture wells.

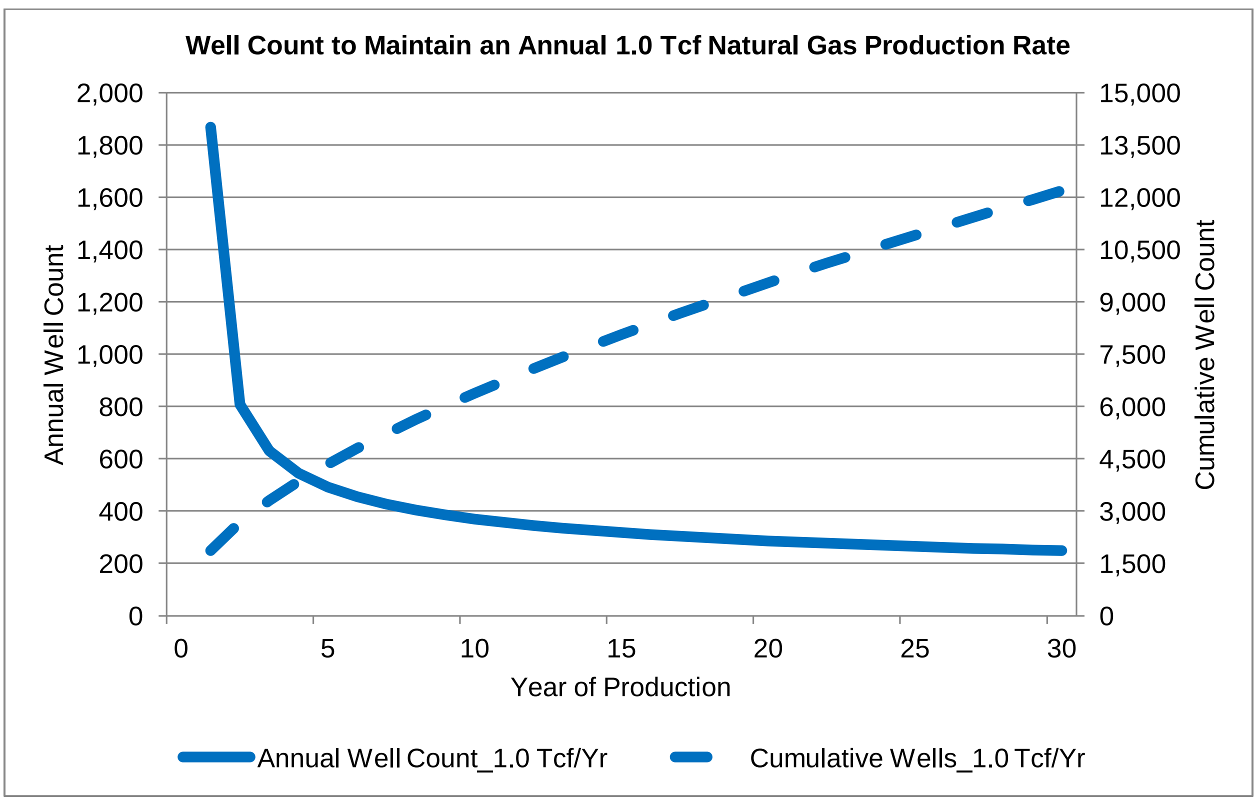

Figure 8. Annual and cumulative well counts to maintain an annual 1.0 Tcf natural gas production rate for thirty years.

A sensitivity analysis is performed to investigate the impact of long-term well production decline rates on average well EUR estimates. The baseline model is the hyperbolic curve average well model described above, in which the decline rate decreases continuously over a well's production life, which is shown in Fig. 9. For comparison, average well EUR's are calculated for constant terminal annual well production decline rates of 6% and 10%.

The timing of when the constant terminal decline rates take effect is determined by the decline rate trajectory of the baseline hyperbolic curve estimates. That is, the month when the hyperbolic curve model reaches a 10% decline rate, the decline rate is held constant at 10% from that point forward (terminal), and likewise for the 6% terminal decline rate model. Graphic representations of the 6% and 10% terminal decline rate models are presented in Fig. 9. Notice that the 10% terminal decline rate takes effect earlier in a well's production life than does the 6% terminal decline rate and hence has a greater impact on the well's EUR.

The sensitivity of average well EUR to the two changes in annual production decline rates is presented at the bottom of Table 2. The 6% terminal decline rate decreases well EUR by 5% compared with the baseline hyperbolic curve well EUR, and the10% terminal decline rate decreases average well EUR by 16%. It appears that E&P companies are using low-end average well EUR estimates to book reserves, which can accommodate a 10% terminal decline rate. For example, Southwestern Energy is currently booking reserves based on a 2.4 Bcf well EUR [3].

Because of the short five year well production history for Fayetteville Shale horizontal wells with advanced hydraulic fracturing, it is impossible to know with certainty the long-term average well production decline rate. To provide insight into what is occurring to date, a five year aggregate average well production history is presented in Fig. 10. The average annual decline rates for each of the five years of aggregate well production history are: Years 1-2 = 49%; Years 2-3 = 36%; Years 3-4 = 29%; and Years 4-5 = 16%.

Another five to eight years of well production is required before knowing the true long-term trajectory of well production decline rates. It is interesting to note that the aggregate forty-year average well EUR has increased from 1.7 Bcf EUR to 1.8 Bcf EUR with the addition of fifteen months of well production data. The current aggregate thirty-year average well EUR is 1.7 Bcf.

Attention is now turned to an assessment of the EIA 2011 technically recoverable resource (TRR) estimate for the Fayetteville Shale, which is presented in Table 1. The issue is whether the EIA's 27.32 Tcf TRR estimate, which is based on an average 2.25 Bcf well EUR and well development of eight wells per square miles over a 1,518 square mile well development area, is reasonable. The analysis involves evaluating well development area and well performance.

The core well development area for the eastern section of the Fayetteville Shale is determined by calculating the number of well completions by county and evaluating average well production rates for first full month of well production. The number of well completions by county is presented in Fig. 11, average first full month well production totals by county are presented in Fig. 12. From the information provided in Fig. 11 and Fig. 12 it is clear that Van Buren, White, Conway, Cleburne, and Faulkner counties comprise. The core well development area for the eastern section of the Fayetteville Shale corresponds to the area labeled core in Fig. 1.

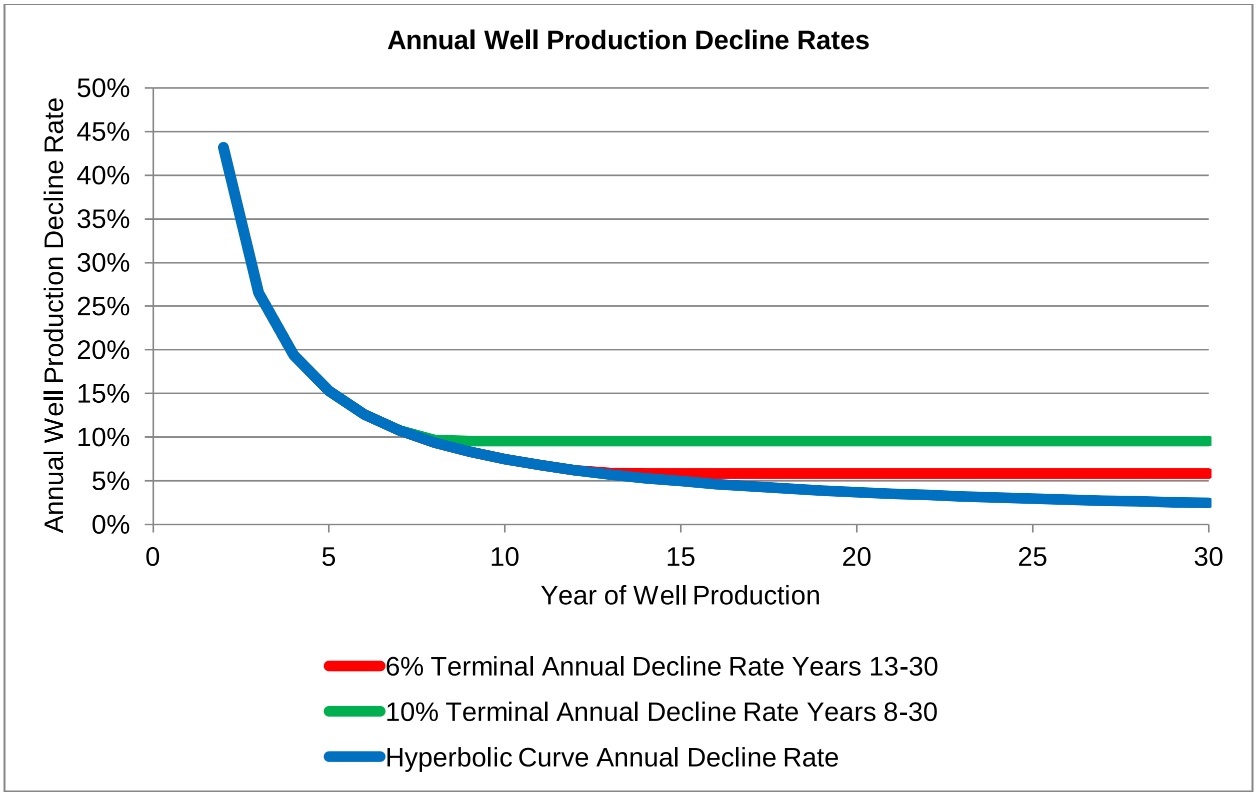

Figure 9. Average annual well production decline rates.

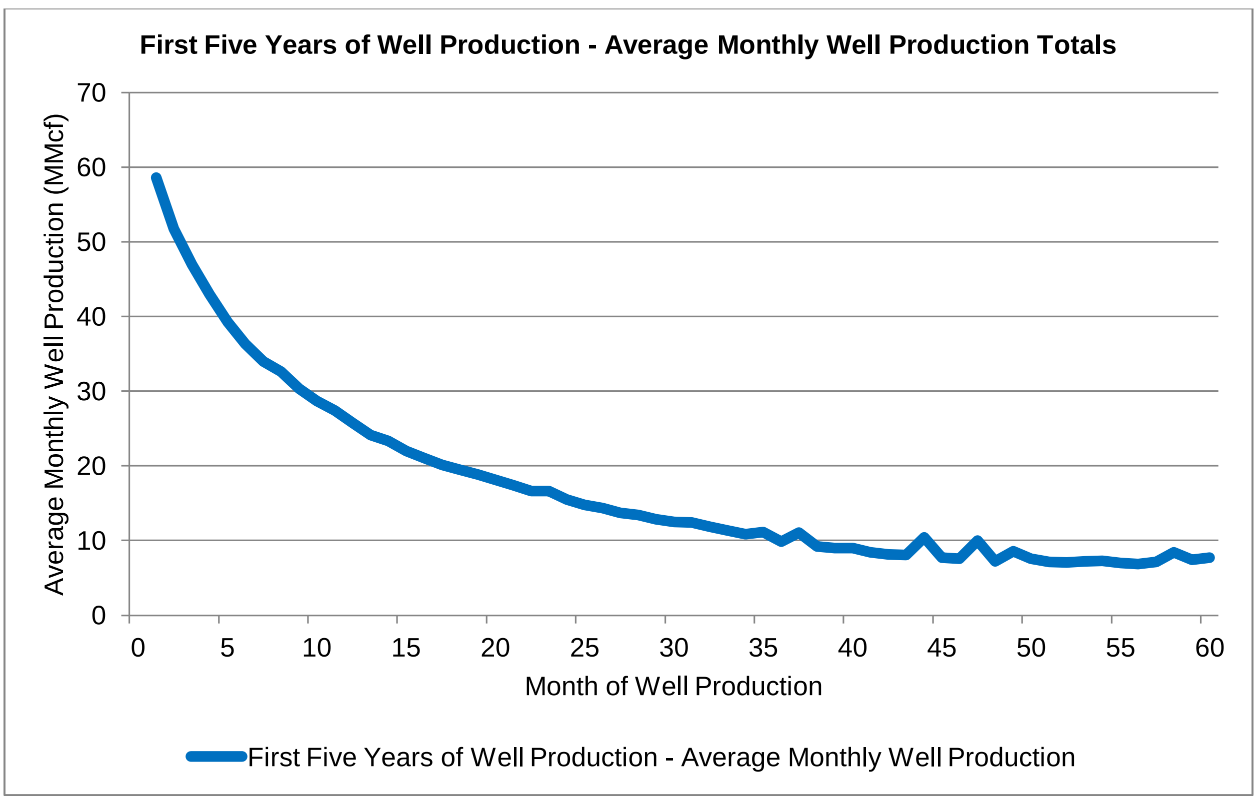

Figure 10. Actual average monthly well production, December 2005 - December 2011.

Ninety-six percent of total Fayetteville Shale well completions are in these core counties. The best well performance is in Van Buren and Conway counties, but the lowest well production totals in White, Cleburne and Faulkner counties is only about twenty percent less than the highest totals in Van Buren and Conway counties. Annual well completions are increasing in Independence County, but well performance is significantly less than that in the core counties.

The percentage of the county area suitable for well development is estimated by inspection of the well location map in Fig. 13 [2]. Total county land area and estimates of the county land area that is available for well development are presented in Table 3. Also, Table 3 contains an estimate of the total number of wells that can be drilled under the assumptions of eight wells per square mile and that 75% of the estimated county well development area is actually suitable for well development. The net well development area estimate is 1,580 sq. mi., which is a little greater than the EIA derived 1,518 sq. mi. well development area in Table 1.

To estimate ultimate gas recovery, the estimated number of wells for the well development area is multiplied by the EIA's 2.25 Bcf average well EUR. The result is 28.4 Tcf. This is 4% greater than the EIA's 27.3 Tcf TRR estimate of for the eastern section of the Fayetteville Shale.

The average well production profiles strongly suggest that the EIA average well EUR of 2.25 Bcf is attainable with current well design and technology. The addition of just fifteen months of well production increased the aggregate forty-year average well EUR from 1.7 Bcf to 1.8 Bcf, and the aggregate thirty-year average well EUR is 1.7 Bcf. With current well designs and technology, the aggregate average well EUR will likely exceed the EIA's 2.25 Bcf average well EUR within ten years. Also, the net well development area estimate indicates that the number of wells to achieve a 27 Tcf ultimate production level is achievable.

In conclusion, when well saturation of the high quality core area of the Fayetteville Shale occurs, average well production will decline significantly and require increases in wellhead gas prices to cover well costs. From the well count estimates to maintain an annual 1.0 Tcf gas production rate with a 3.1 Bcf average well EUR, a 1,580 sq. mi. net well development area, and eight wells per sq. mi., well saturation of the highest quality core area is likely to occur around 2035. If the annual production rate is increased to 1.5 Tcf by 2020, then well saturation occurs around 2025.

Table 3. Counties Comprising the Core Well Development Area of the Fayetteville Shale.

	Total Area (sq. mi.)	% of Total Area Developed	Developed Area (sq. mi.)	Number of Wells (75% of Developed Area)	Total Gas Production with 2.25 Bcf Well EUR (Tcf)
Core Counties					
Conway	556	80%	445	2,670	6.0
Van Buren	712	70%	498	2,988	6.7
Cleburne	553	70%	387	2,322	5.2
White	1,034	50%	517	3,102	7.0
Faulkner	647	40%	259	1,554	3.5
Totals	3,502	60%	2,106	12,636	28.4

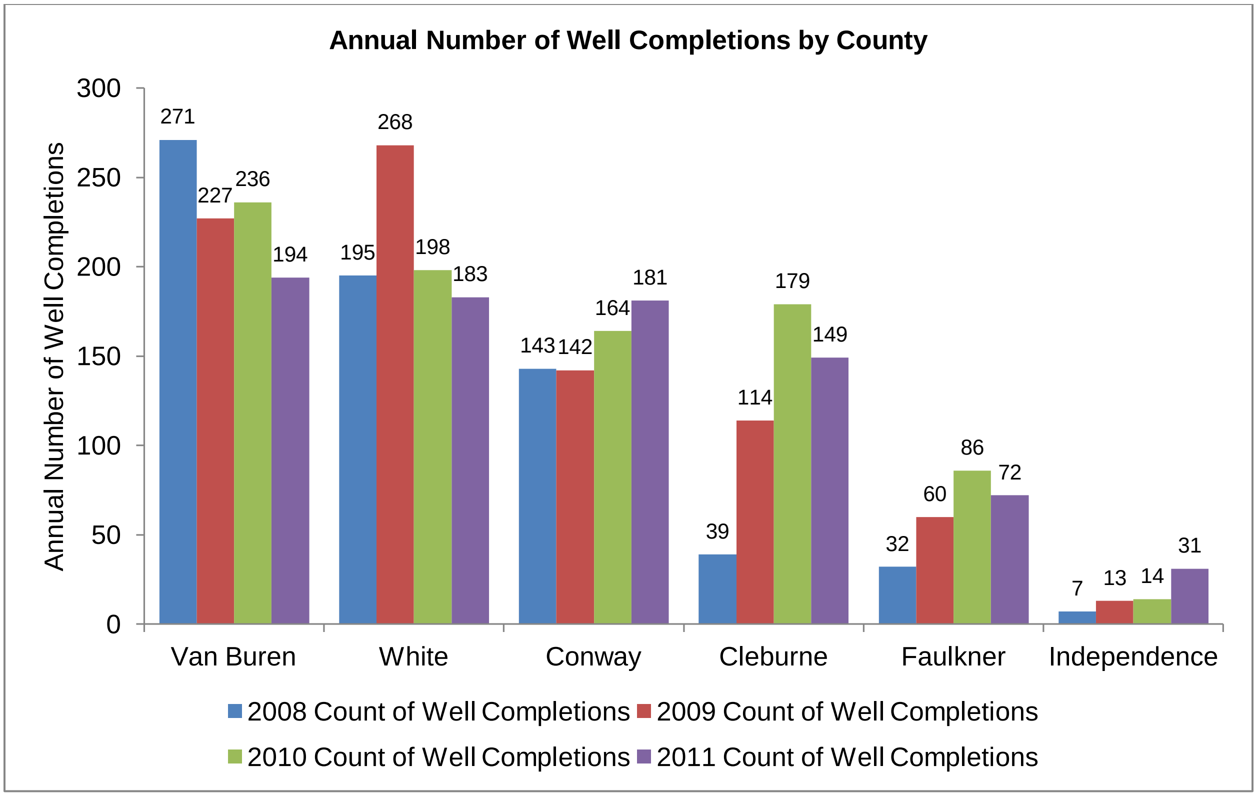

Figure 11. County counts of well completions.

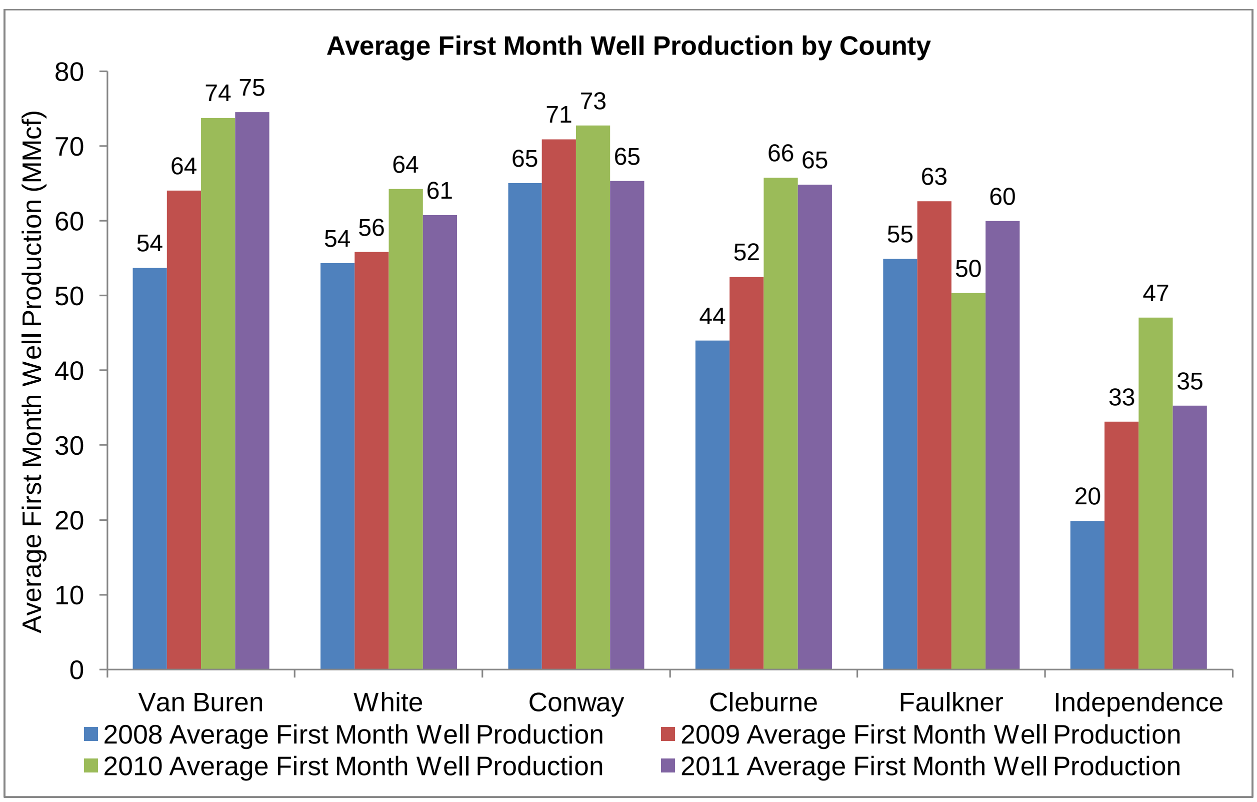

Figure 12. County average first month well production.

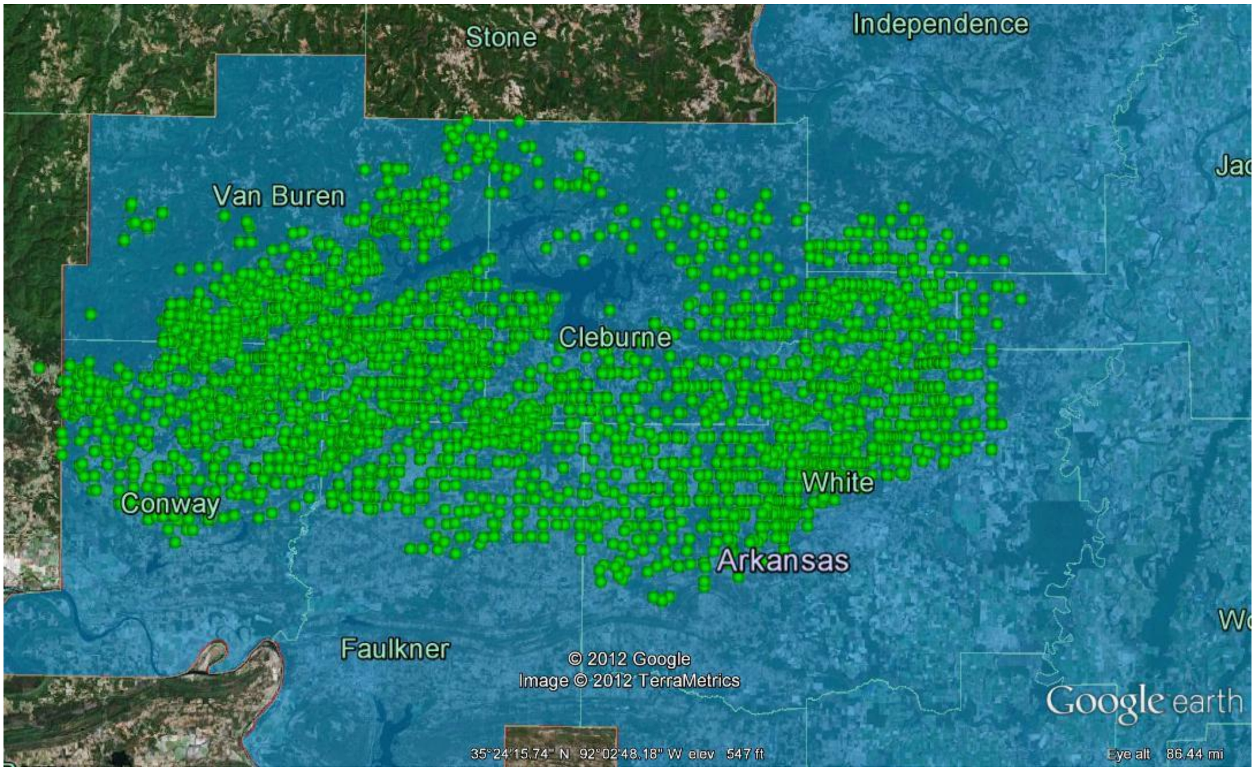

Figure 13. Well locations in the eastern section of the Fayetteville Shale (Source: Arkansas Oil and Gas Commission, Google Earth Field Boundary Map for Field B-43).

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