KIMMERIDGE
Energy

Deconstructing the Fayetteville

Lessons from a Mature Shale Play

June 2015

Introduction

The Fayetteville shale gas play lies in the eastern Arkoma Basin, east of the historic oil and gas fields in the central and western parts of the Basin. As one of the most mature, well-developed and well-understood shale gas plays, it offers an unparalleled dataset on which we can look back and review how closely what we "thought we knew" matches "what we now know", and what lessons there are to be learned in the development of shales and the distribution of the cores of these plays.

As we have previously noted (see Figure 1), identifying the core of a shale play is akin to building a Venn diagram based on a number of geological factors. By revisiting the Fayetteville we can rebuild this diagram and overlay it on what is now a vast database of historical wells to see whether it matched expectations, and if not, why not. The data also allows us to review how the development of the play changed (lateral length, completion, etc.) and the variance in performance between operators presents valuable lessons in whether success is all about the rocks, or whether operator knowledge/insight can make good rocks bad or vice versa.

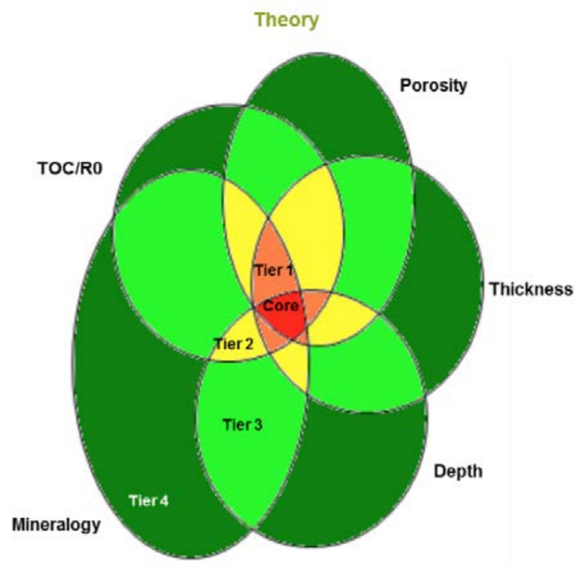


Figure 1: Schematic of gradational overlap of geologic attributes that define the core of an unconventional resource play

Background

The Fayetteville shale lies in the eastern Arkoma Basin and ranges in depth from outcrop in the north to 9,000' at the southern end of the play, with drill depths primarily between 3,000' and 6,000'. It has over 5,000 producing gas wells and is considered a development-stage shale play, being one of the earliest discovered in the US. Production began in 2004 and reached over 2.8 Bcf/d, with cumulative production to date of around 5.7 Tcf and estimated recoverable resources of 20-30 Tcf.

Although the rig count has dropped off steeply in the Fayetteville, in line with the drop in natural gas prices, rig productivity has increased with more wells drilled per rig and well productivity has improved, driven by longer laterals with more stages, higher volume of frac fluid and increased amount of proppant. This has resulted in production holding steady at >2.6 Bcf/d despite fewer wells being drilled. Productivity gains are ongoing and are primarily driven by Southwestern Energy (SWN), the only company that continues to run a significant drilling program in the play. These factors combined, the Fayetteville represents one of the preeminent datasets for understanding the impact of geology, completions and landing zones for an unconventional play.

Evolution of the Play: Concept Generation

At its most basic level, a shale play is simply the source rock for conventional oil or gas fields. In any given hydrocarbon basin there must be a source rock that generated the oil and gas produced from conventional fields. Only in rare instances does the oil or gas migrate laterally over long distances from source rocks outside of the basin. Migration from source to trap is predominantly vertical, so in basins with active shale plays, conventional oil and gas fields often sit directly above the source kitchen, or updip.

Therefore, searching for potential shale plays should be as simple as looking within proven hydrocarbon basins and identifying the various source rocks and their generative kitchens. With respect to the Arkoma Basin, the vast majority of hydrocarbons produced from conventional reservoirs has been gas, and the Basin is understood to be generally overmature with the thermal maturity of source rocks having Vitrinite Reflectance values of 1.0-4.0 Ro%. This suggests good potential for shale gas, but limited potential for a tight oil play.

Notably, the vast majority of conventional gas fields lie to the west of the Fayetteville shale play fairway, so the majority of historic drilling activity occurred outside of this area. However, the Fayetteville shale play was reportedly discovered by a SWN geologist when gas production from a Batesville sandstone reservoir, directly below the Fayetteville shale, exceeded the volumetric potential of the sandstone reservoir. This implied that gas was also being contributed by a formation other than the Batesville sandstone, with the logical candidate being the overlying gas mature source rock, the Fayetteville shale.

Throughout the Arkoma Basin there exist several organic rich and gas-mature shales, which have the potential to be shale plays. These are the Mississippian Fayetteville and Caney shales, which are stratigraphic equivalents, and the Upper Devonian Woodford and Chattanooga shales, also stratigraphic equivalents (Figure 2). These are the obvious candidates for shale gas plays.

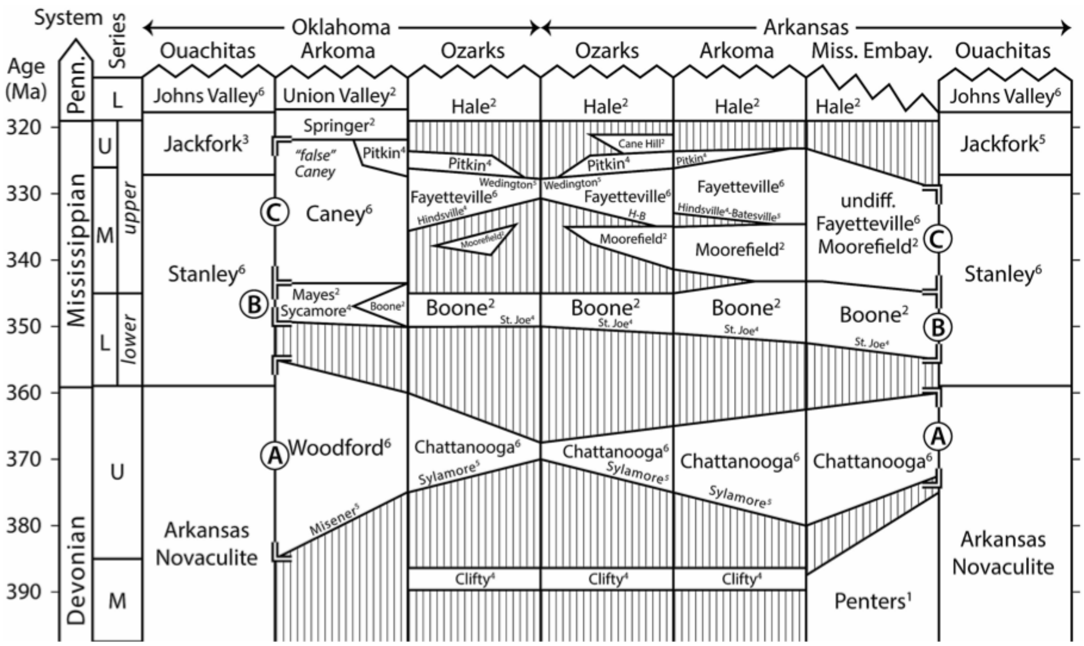


Exhibit 2: Stratigraphy of the Arkoma Basin (Houseknecht et al. 2014)

We can map out the distribution of these shales using log data, since there is insufficient public geochemical data. As a general rule, organic-rich shales are more radioactive and there tends to be a good correlation between Total Organic Content (TOC) and gamma ray. This relationship holds true in the Arkoma Basin (see Figure 3), which allows us to map out the spatial distribution of potential source rocks using log data.

Using log data from a variety of public sources, including Houseknecht et al. (2014), who published data for around 180 wells across the Basin, we mapped out the gross and net high gamma ray thicknesses of the Fayetteville-Caney shale. Per Figure 4, gross thickness was taken as the thickness from the top of the first high GR (>150 API) shale to the bottom of the last high GR shale within the Fayetteville formation. Net thickness is the sum of all rock within the Fayetteville with GR>150 API, as according to our methodology this should capture the organic rich shales with TOC>2%.

Note Figure 4 also shows deep resistivity logs, which are red when the resistivity exceeds 30 ohm, which can indicate hydrocarbon saturation. We know from the thousands of wells drilled into the Fayetteville, that the most productive interval is the Lower Fayetteville, where GR is consistently >150 API and resistivity is high.

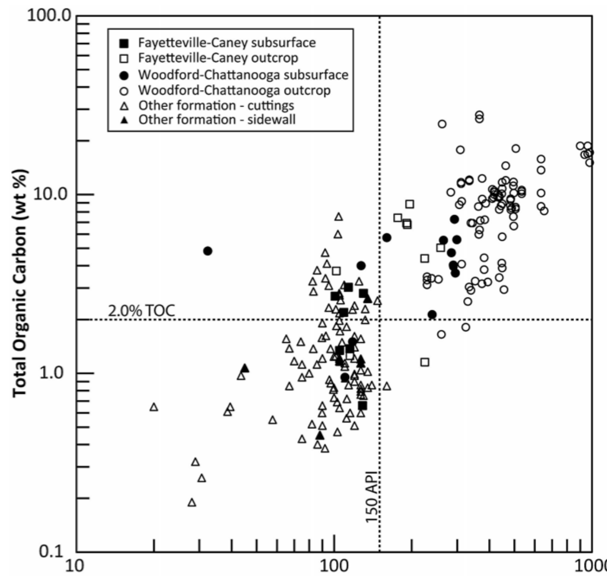


Figure 3: Relationship between gamma ray and TOC content for subsurface and outcrop samples from the Arkoma Basin (Houseknecht et al., 2014)

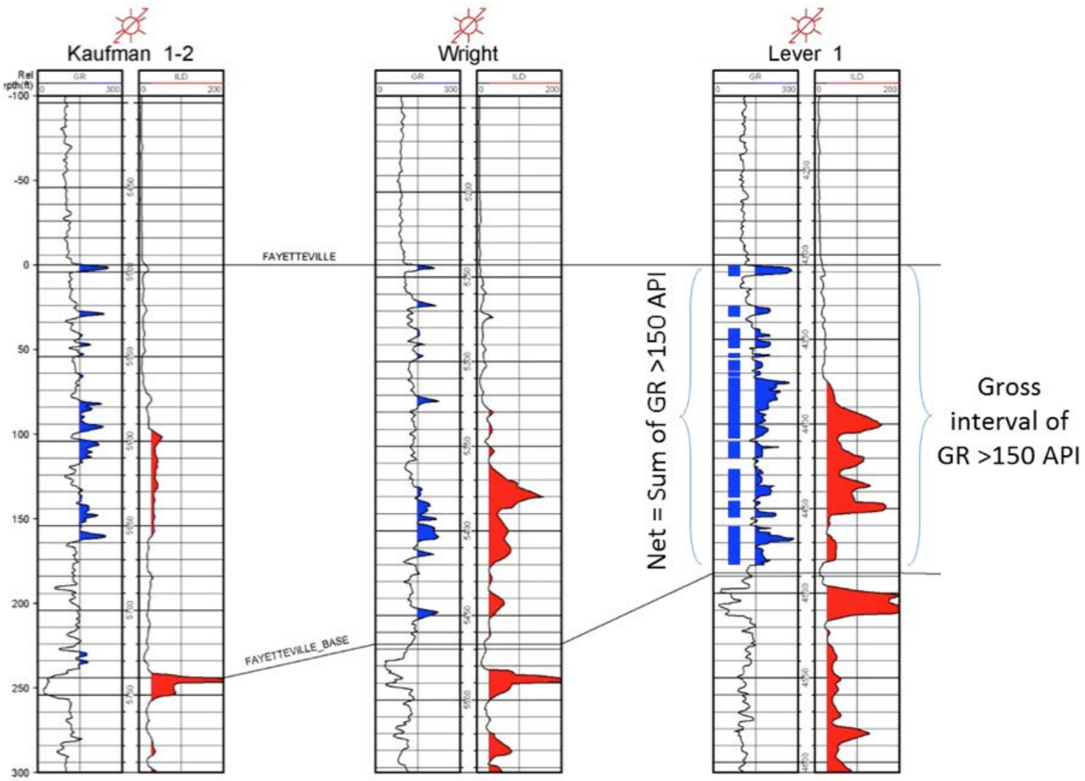


Figure 4: Examples of well logs used to measure gross and net thickness of high gamma ray Fayetteville-Caney shale across the Arkoma Basin (AOGC, AGS, DrillingInfo, Houseknecht et al. 2014)

Using gross thickness, we can see that the Fayetteville-Caney formation is deposited across the Arkoma Basin and contains high gamma ray shales, so it should be organic-rich and therefore a source rock if thermally mature (Figure 5). However, the net thickness map gives us a better sense of the relative richness of the rock across the Basin, and is therefore more useful in identifying the shale play fairways (Figure 6). For the Fayetteville, this clearly lies in the eastern Arkoma Basin within Pope, Van Buren, Conway, Cleburne, Faulkner and White Counties in Arkansas. These counties are where the bulk of Fayetteville exploration and development drilling has occurred, despite the fact that this area saw very modest amounts of historic conventional drilling.

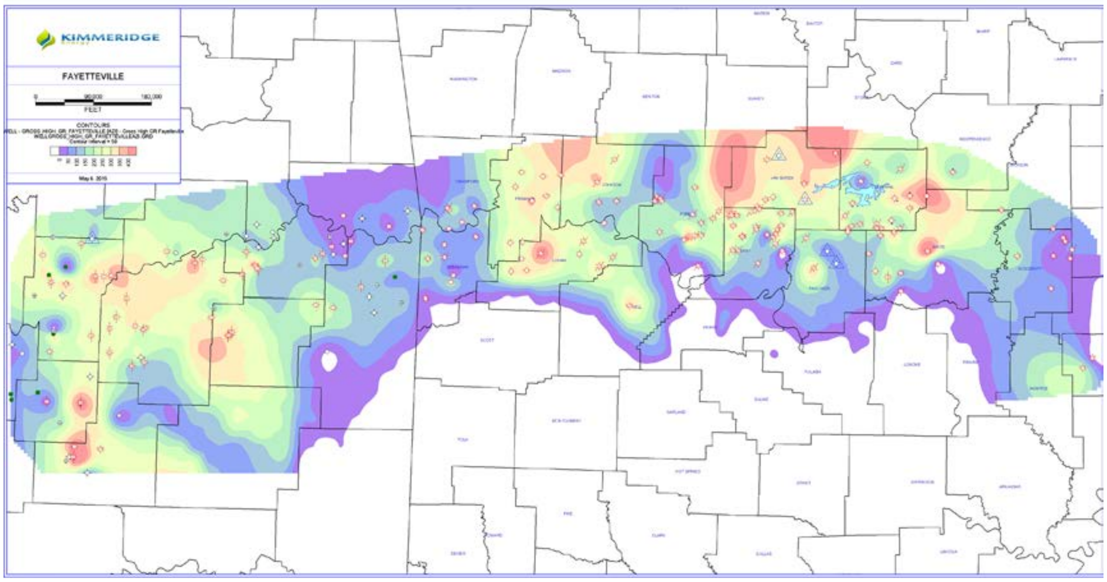


Figure 5: Gross high gamma ray thickness map of Fayetteville-Caney shale across Arkoma Basin
(AOGC, AGS, DrillingInfo, Houseknecht et al. 2014)

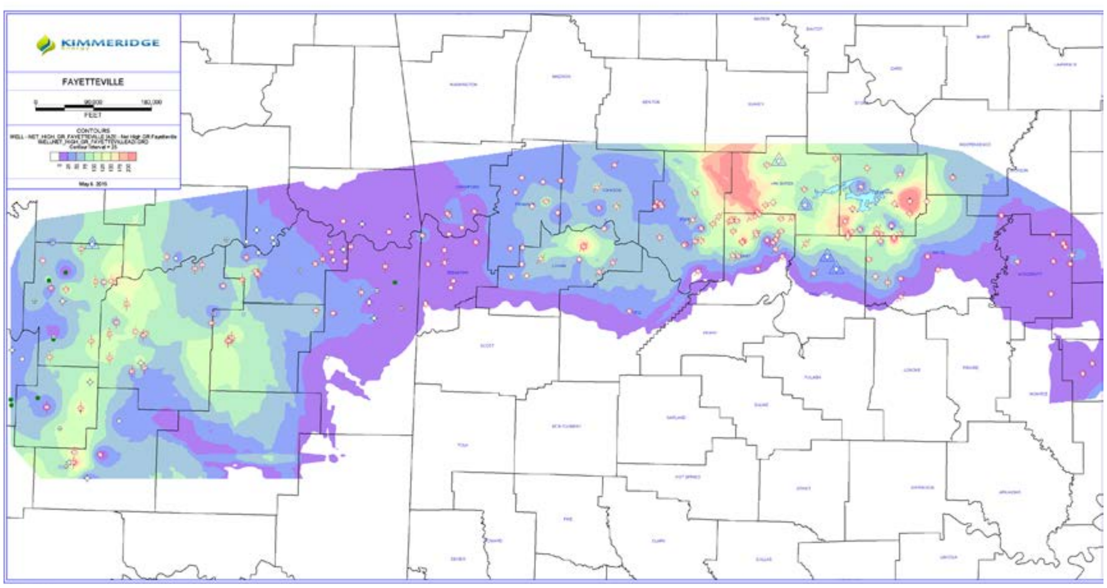


Figure 6: Net high gamma ray thickness map of Fayetteville-Caney shale across Arkoma basin
(AOGC, AGS, DrillingInfo, Houseknecht et al. 2014)

Evolution of the Play: Defining the Core

Now that we have identified the Fayetteville play fairway using regional log data to map out spatial distribution of potential source rocks, we can turn our attention to defining the core. Throughout the play area, the Fayetteville shale has excellent shale gas characteristics:

- Present day TOC ~1.5-3.5% and original TOC 4-13+%
- Mixed type II/III kerogen (mixed oil and gas prone)
- Dry gas window maturity Ro 2.0-4.0%
- Laterally homogeneous, organic-rich shale thickness ~100-400'
- Normal reservoir pressure (~0.433 psi/ft)
- High brittle content and natural fractures
- Although shales are considered relatively homogeneous versus other rock types, there are significant variations in properties across a basin that impact the quality of the shale as an unconventional reservoir. The Fayetteville is typically sub-divided into Upper, Middle and Lower units:
- The Upper Fayetteville is demarcated by a thin, high-gamma ray shale at the top followed by a sequence of thin interbedded high GR shales. This unit is clay-rich and being tested as a new completion zone with good initial results.
- The Middle Fayetteville tends to have lower GR than either the Upper or Lower units and is much thinner, so not a target interval.
- The Lower Fayetteville is the thickest unit with consistently high GR throughout, high resistivity and typically high gas saturation. It has lower clay content and higher carbonate content than the Upper or Middle units, so has been the main target interval in the play to date.

Looking at a regional stratigraphic cross-section showing GR logs (Figure 7), we can see that the Fayetteville formation has a pretty consistent thickness of 200-300' across the extent of the play from west to east. However, although clearly the same formation, the logs show considerable variation between wells, especially in the Upper and Middle units, with the Lower Fayetteville appearing to be the most consistent unit across the Basin.

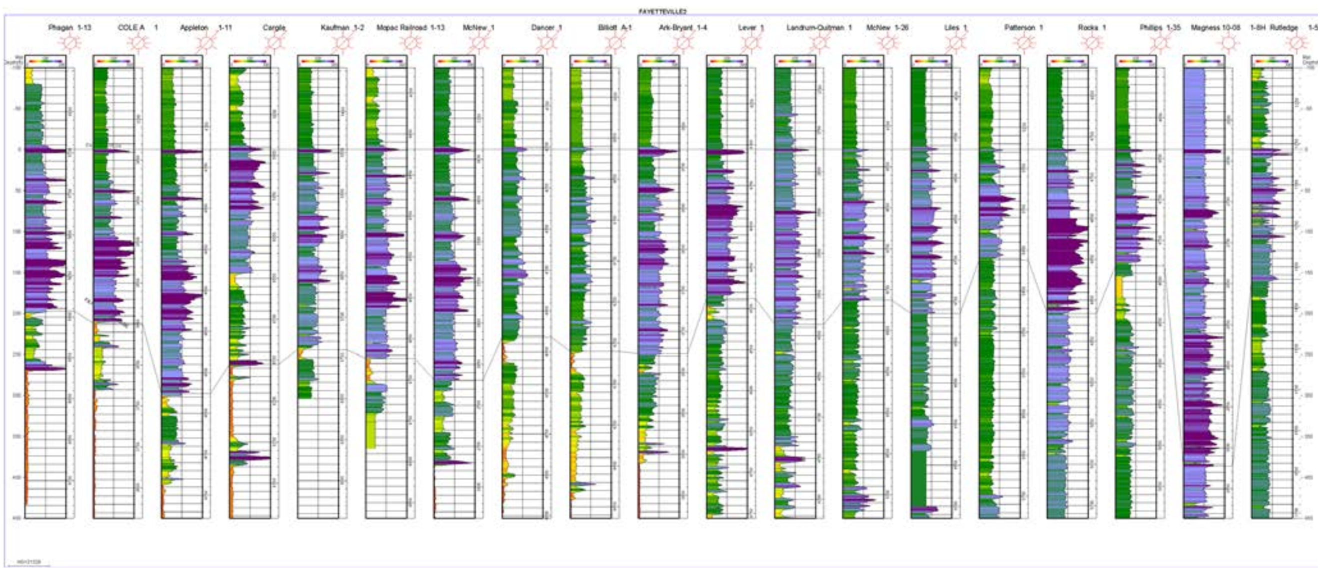


Figure 7a: W-E cross-section across Arkoma Basin with gamma ray logs and location map of cross-section (AOGC, AGS, DrillingInfo)

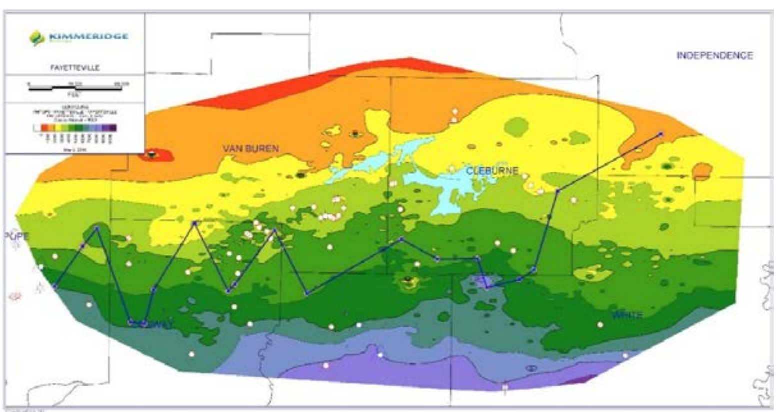


Figure 7b: W-E cross-section across Arkoma Basin with gamma ray logs and location map of cross-section (AOGC, AGS, DrillingInfo)

The core of the play, defined by the best well performance, occurs in southeastern Van Buren, northeastern Conway, northern Faulkner and southern Cleburne Counties. Southwestern is the primary operator in this area and initially leased here based on the optimal overlap of these geological factors; but they also leased away from large Mississippian faults and at depths of 3,000-6,000' where drill costs are low and reservoir pressure is sufficiently high. We created a series of maps (Figures 8-12) using well and log data, which in turn were overlaid to derive a core area for the Fayetteville play (Figure 13). We used the following parameters to define the geologic core:

- Depth 3,000-6,000' (low drilling costs, but sufficient reservoir pressure)
- Gross thickness >200' (sufficiently thick to contain fractures within formation)
- Net organic-rich thickness >75' (sufficient thickness of net pay)
- Thermal maturity Ro 2.0-2.5% (dry gas, but no/low CO_2)
- Present day TOC >1.5% (original TOC would have been >4% providing sufficient organic richness to saturate the formation)

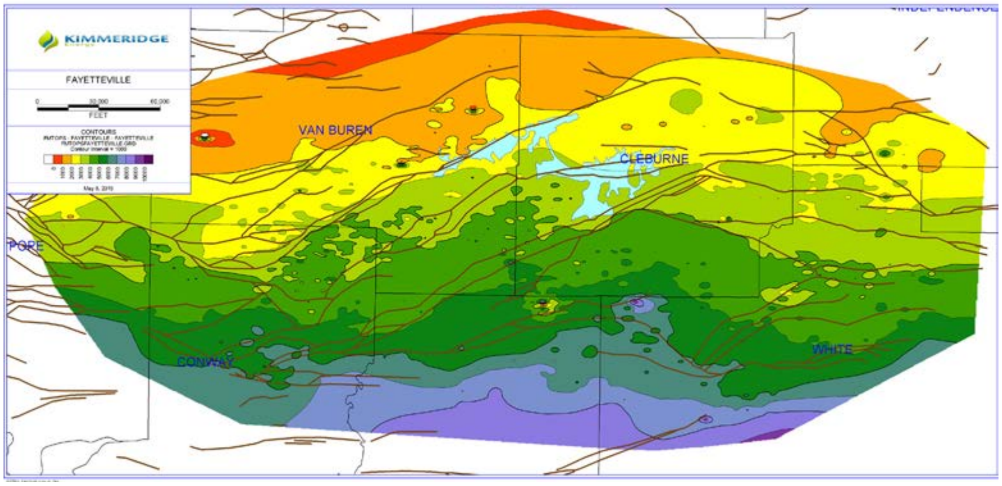


Figure 8: Fayetteville shale drill depth and fault map (AOGC, AGS, DrillingInfo, Houseknecht et al. 2014)

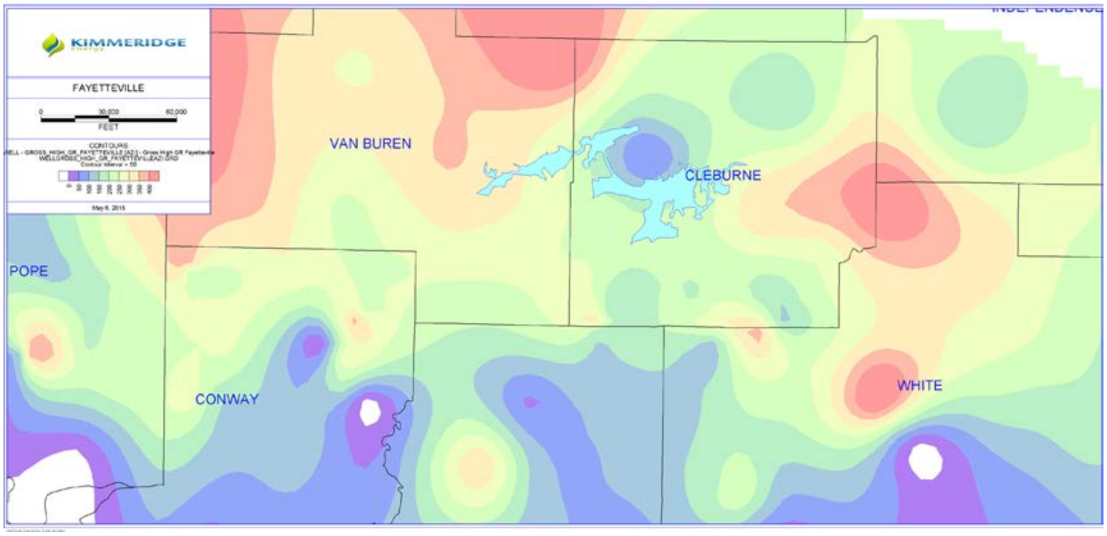


Figure 9: Fayetteville shale gross thickness map (AOGC, AGS, DrillingInfo, Houseknecht et al. 2014)

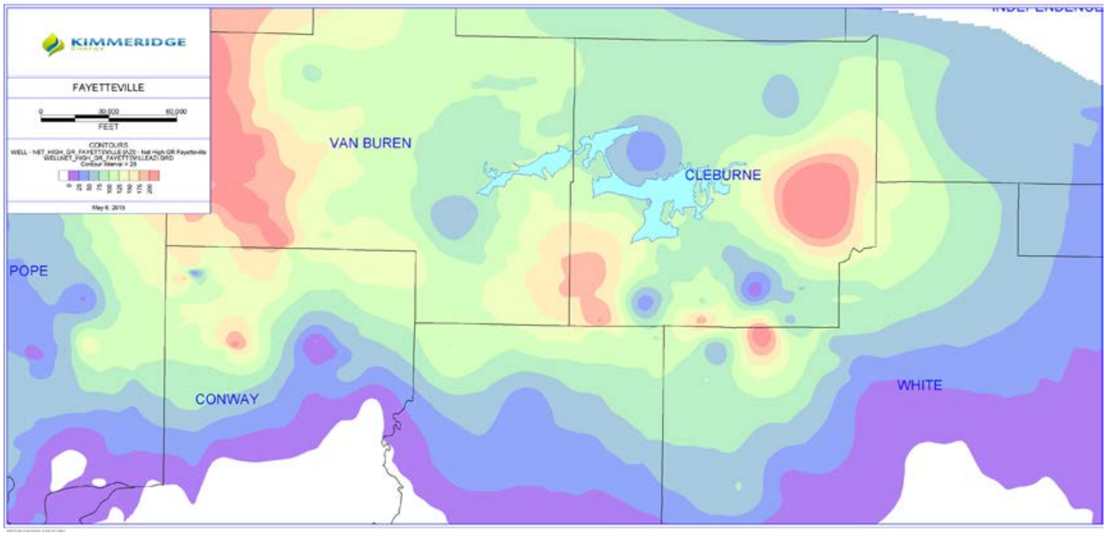


Figure 10: Fayetteville shale net high GR thickness map (AOGC, AGS, DrillingInfo, Houseknecht et al. 2014)

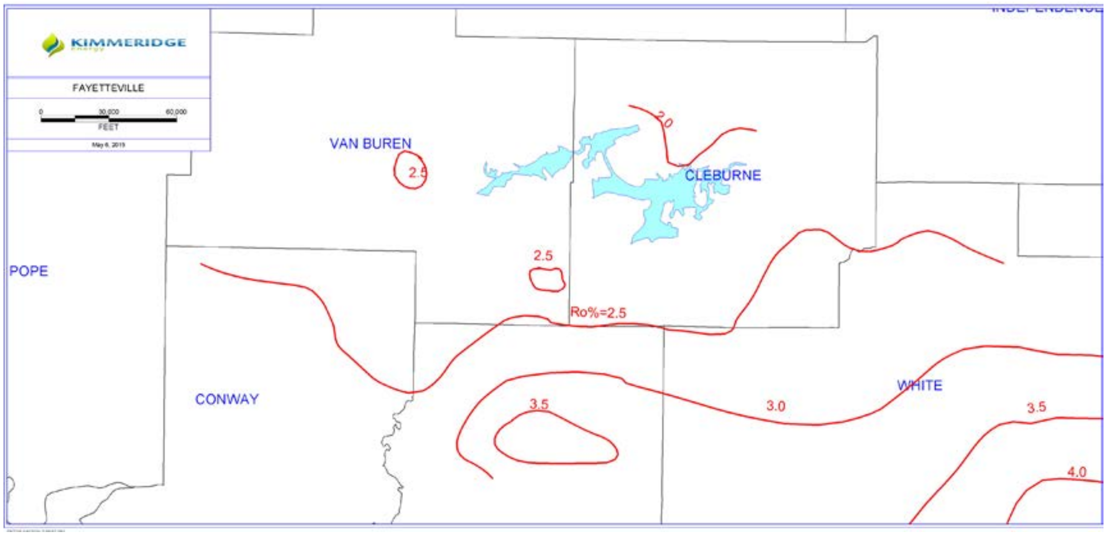


Figure 11: Fayetteville shale thermal maturity/VR contour map (EIA, DrillingInfo)

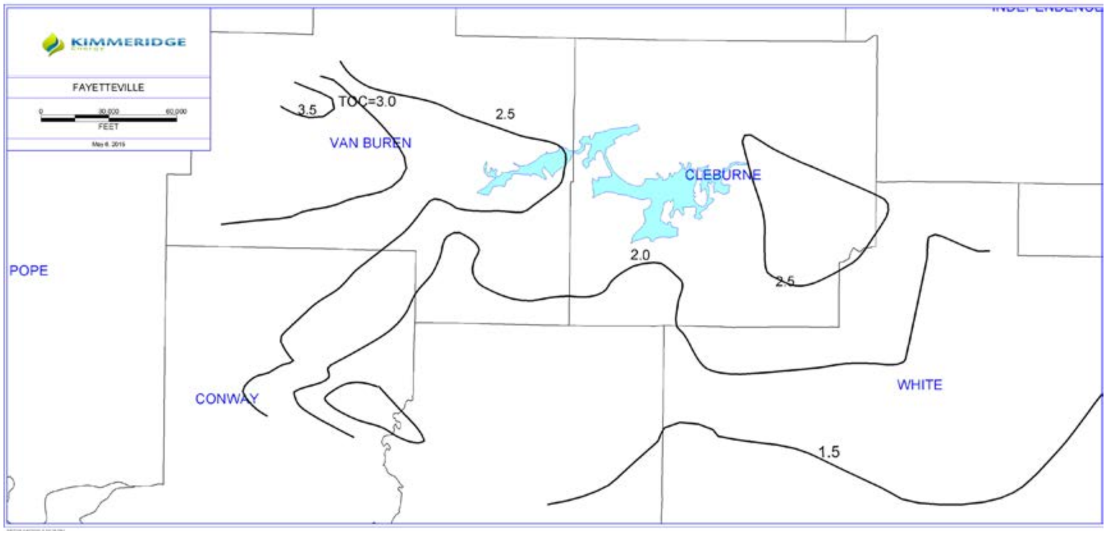


Figure 12: Fayetteville shale TOC distribution map (EIA, DrillingInfo)

In Figure 13, we have derived the geologic core (black dashed outline with hatching) by overlaying the various attributes. This in turn was overlaid on an Initial Production map (Figure 14), based on the more than 5,000 producing Fayetteville wells; notably, most of the wells with the best IP's do plot spatially within the geologic core, which suggests that ex-ante mapping of the core prior to any drilling results in new or emerging basins should be effective using analogs from successfully developed shale plays such as the Barnett, Fayetteville, Bakken and Eagle Ford (albeit with an understanding that all shale plays are created differently). In fact, we have done a similar exercise for both the Barnett and Bakken, where the best wells also plot spatially within our defined geologic core.

Although IP is a good indicator of well performance, it is not the best indicator over the life of the well, as production can vary considerably. However, for the vast majority of development wells in mature plays such as the Fayetteville or Barnett, there is a solid relationship between IP and EUR. So EUR can be inferred from IP. Nevertheless, we have looked at analysis from Browning et al. (2014), who defined the best parts of the play by estimating EUR per section using a log-based methodology that calculates net porosity thickness of the Fayetteville shale and multiplies this by standardized assumptions such as water saturation of 25%, normal reservoir pressure (0.433 psi/ft), etc., to get a GIP/section. An EUR/section was derived by looking at well productivity per section (Figure 15). Notably, most of the high EUR sections lie within our geologic core.

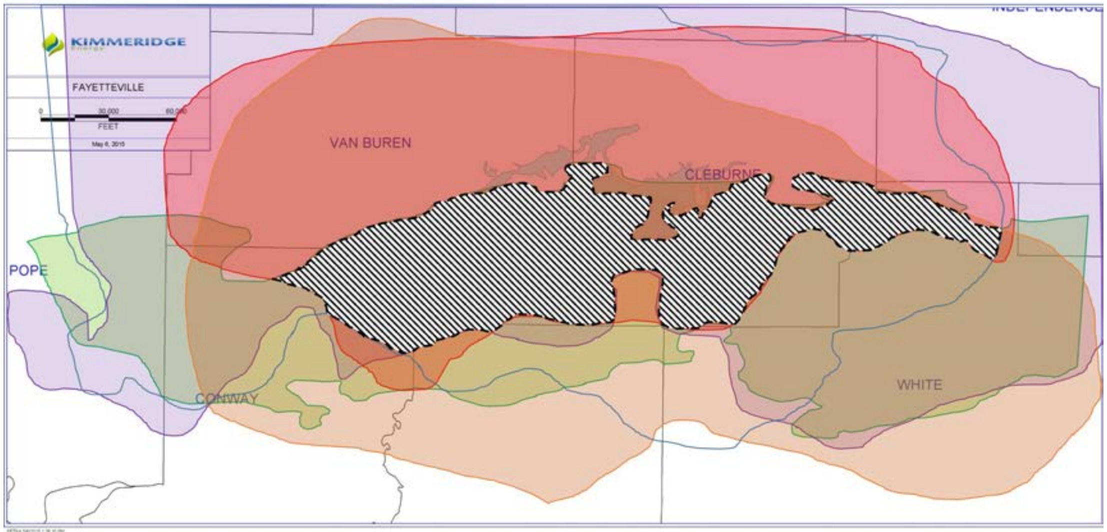


Figure 13: Defining the core of the Fayetteville shale (EIA, DrillingInfo, AOGC, AGS, Houseknecht et al. 2014). Note that green is drill depths of 3,000-6,000'; blue outline is gross thickness >200'; purple is net thickness >75'; red is Ro 2.0-2.5%; and orange is TOC >2%.

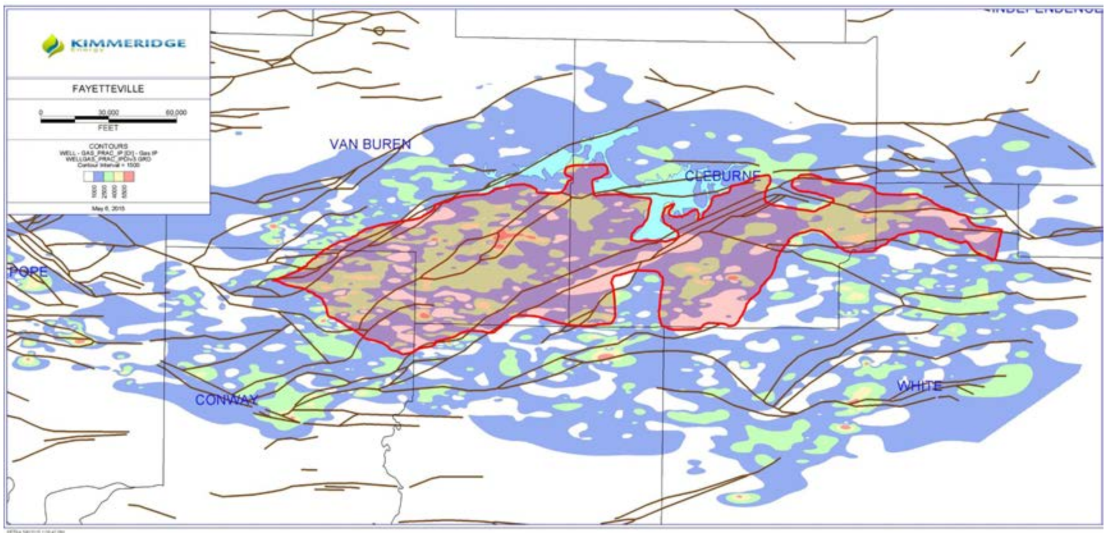


Figure 14: 30-day Initial Production contour map with geologic core overlaid in red
(EIA, DrillingInfo, AOGC, AGS, Houseknecht et al. 2014)

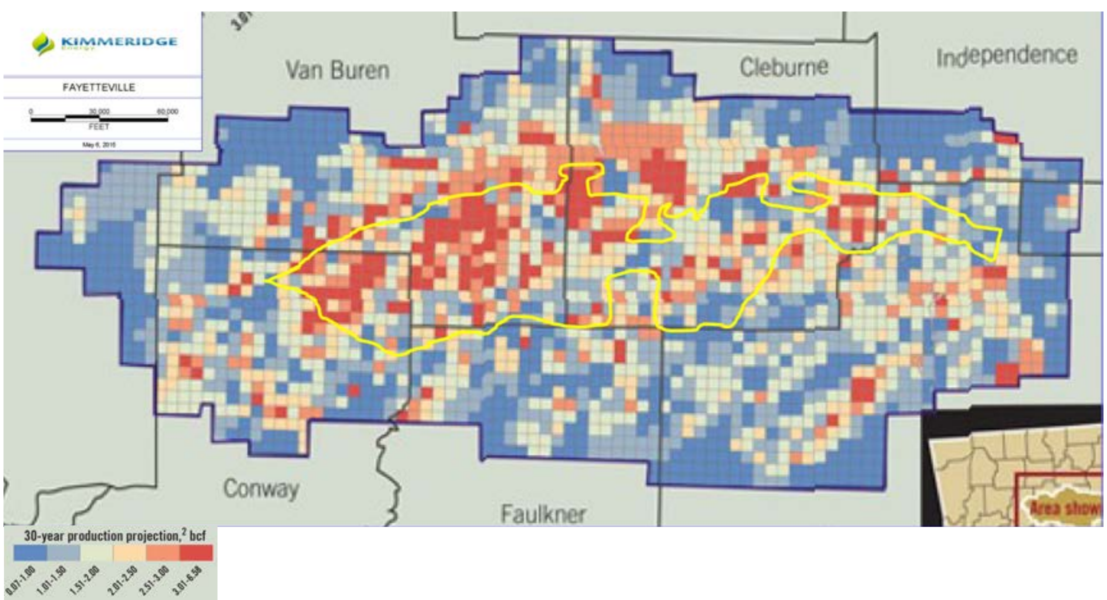


Figure 15: Estimated EUR map with geologic core overlaid in yellow (Browning et al. 2014, EIA, DrillingInfo, AOGC, AGS, Houseknecht et al. 2014)

Deconstructing the Core – Drilling Results by Vintage

In order to further refine our understanding of the core of the play, we have taken the top quartile wells by vintage (using IP per 1,000' of lateral to screen for the top quartile). The evolution of the core areas can be seen over time in Figure 16, although this is easier to see on an annual basis rather than looking at all years plotted on a single map. Nevertheless, what you do see is top quartile wells drilled in:

- 2004-06: mainly in southern Van Buren, northern Conway and northeastern Faulkner.
- 2007: moved eastward reaching western edge of Cleburne, and a brand new area in White County.
- 2008: moved further north.
- 2009: moved further south and into the center of Cleburne County.
- 2010: moved further in all directions, covering more areas of the play.
- 2011: similar areas to 2010.
- 2012: re-focused in the initial core area in southeastern Van Buren and northeastern Conway.
- 2013: moved back into distal areas such as central Conway, away from the initial core.
- 2014: once again re-focused in southeastern Van Buren, but also in southern Cleburne.

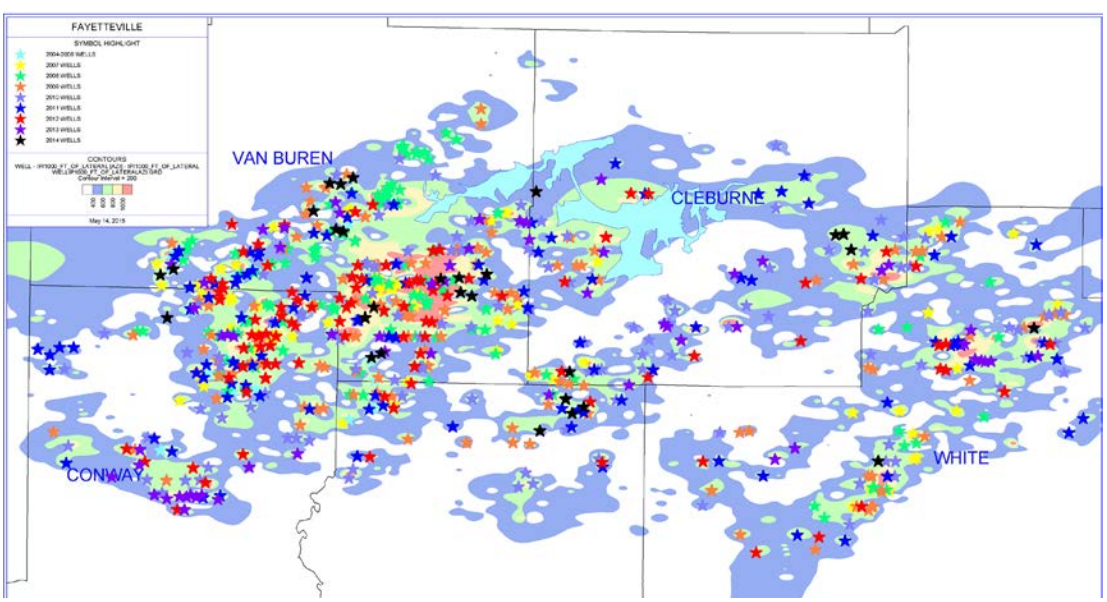


Figure 16: Contour map of IP per 1,000 of lateral versus top quartile wells by vintage (DrillingInfo, AOGC, AGS)

The vast majority of top quartile wells lie in southeastern Van Buren and northeastern Conway, which represent the initial and main core of the Fayetteville shale play. Leasing and drilling started in this area and was focused here throughout 2004-2008, driven by Southwestern's work to define this as the geologic core. During this period gas prices were high, regularly $6-10/mcf.

From 2009-2011, with gas prices lower at $3-5/mcf, top quartile wells appeared more evenly distributed across the play as operators tested new areas in the east such as southern Cleburne and northern White Counties. In 2012-14, with gas prices trading between $2-6/mcf, drilling focused back in the initial core area plus new second tier areas in the east.

Interestingly, by looking at the spatial distribution of top quartile wells by year, we can see a clear deterioration in geology as operators moved outside of the initial geologic core. The average IP per 1,000' of lateral for top quartile wells improved steadily throughout 2004-2008 (Figure 17), as operators stayed within the geologic core but improved their completions to enhance well productivity.

After 2009, as operators stepped outside of the core to test new areas of the play, we can observe a steady decline in average IP per 1,000' lateral for top quartile wells, despite the significant increase in average lateral length during this period. This could suggest that in 2009, operators saw diminishing returns from larger completions; but if this is the case, why did completions continue to get larger?

We know that operators such as Southwestern were constantly testing new completion methods and steadily increased the size of their completions to enhance well economics. Additionally, they were able to consistently drive down drilling and completion costs from inception of the play until the present day, further enhancing economics.

Therefore, it follows that the quality of completions did not worsen from 2009; rather, as we can observe from the spatial distribution of wells over time, operators were drilling wells in areas with worse geology. Indeed, the movement away from the geologic core may also have driven the need for longer laterals as companies tried to offset worse geology.

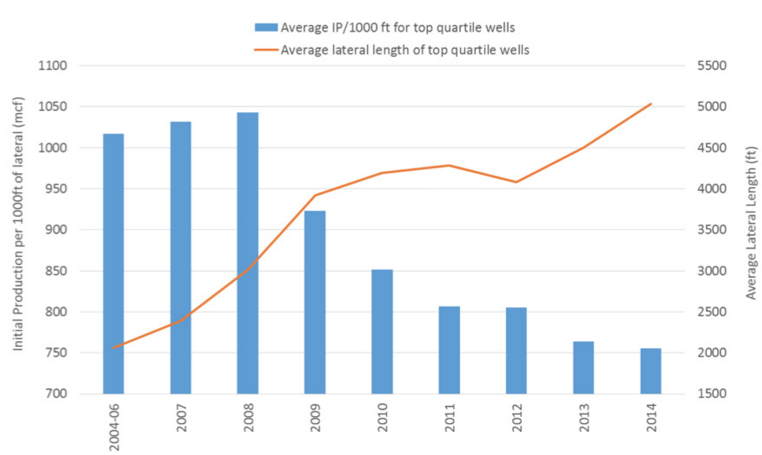


Figure 17: IP per 1,000' of lateral cut-off for top quartile wells vs. average lateral length of top quartile wells (DrillingInfo, AOGC, AGS)

Current State of the Play and Best-in-Class Operators

Although the rig count has dropped off steeply in the Fayetteville, due to sustained low gas prices, production has been relatively stable compared to other shale plays such as the Haynesville (Figure 18), which has seen a very large decline in production. Why is the Fayetteville different? There are a few specific reasons that the play has proved more resilient to low commodity prices.

The Fayetteville shale is unique in that a single company, Southwestern Energy, is extremely dominant, controlling essentially the entire core area. Southwestern discovered the play, aggressively leased the core, rapidly drilled to HBP (hold-by-production) its acreage, and continues to drive improvements in rig and well productivity to this day. Every other company that followed Southwestern into the play has now stopped drilling. BHP stopped drilling in 3Q2013 and XTO, which ran a single rig in 2014, drilled only 12 wells last year and none thus far in 2015.

Southwestern's Fayetteville project is a masterclass in full-cycle execution of a shale play, from developing the initial play concept, through early exploration and de-risking, all the way to full field development. There are specific reasons for:

a. The Fayetteville's greater resilience to low natural gas prices than other shale plays, and
b. Southwestern's success vs. other operators.

Because of Southwestern's dominance in the play, having drilled ~75% of all wells, the two are inextricably linked.

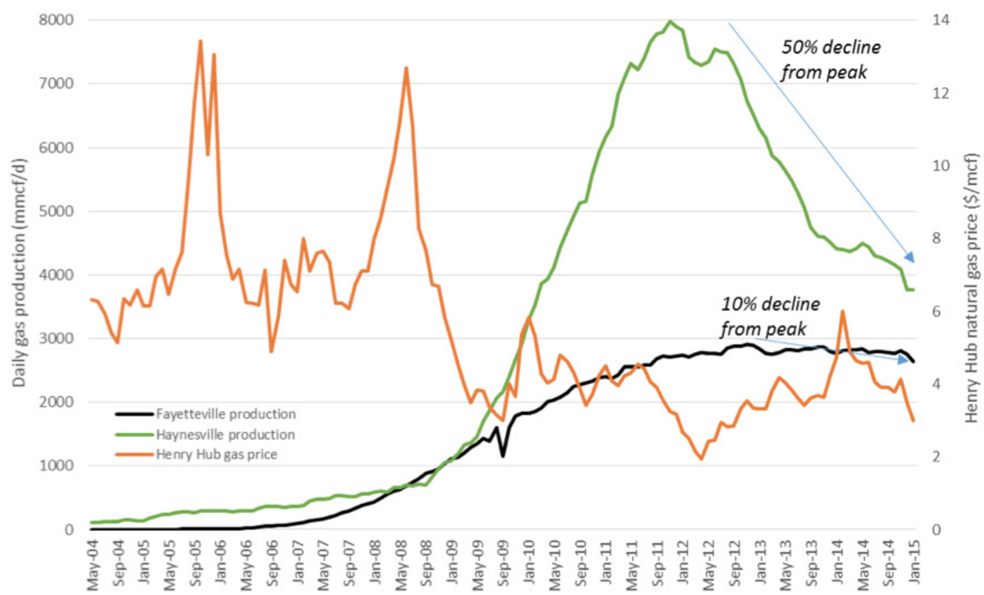
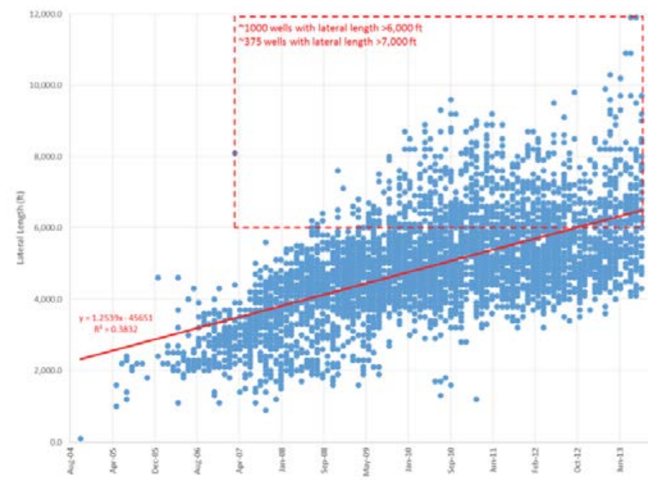


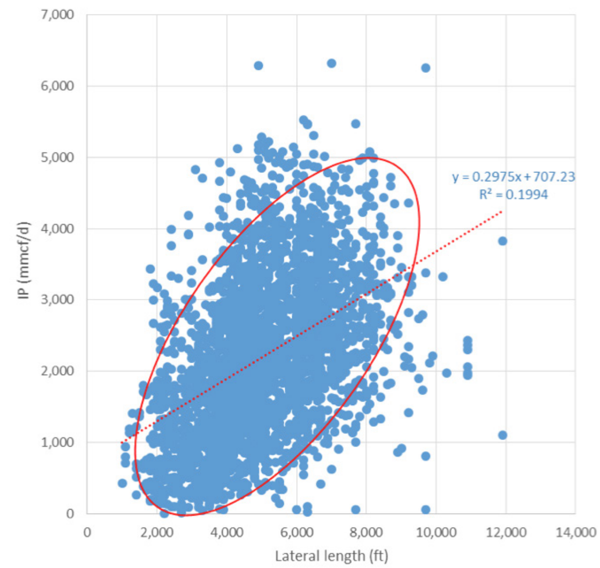
Figure 18: Gas production from the Fayetteville and Haynesville vs. Henry Hub gas prices (EIA, DrillingInfo)

With respect to the Fayetteville's resilience to low gas prices, the primary reasons are the low drilling and completion costs combined with high realizations and solid EUR's, which has kept wells economic. The average well costs around $2.5m to drill and complete, due to low drill depths (3,000-6,000'), short drilling time (~6 days to TD), and standardized completions. However, it should be noted that the preceding numbers are based on Southwestern's wells, which are the lowest cost and most consistent – indeed the company's success at driving down costs and optimizing drilling and completions is largely responsible for putting the Fayetteville at the front end of the North American shale gas supply curve.

With respect to Southwestern's success versus other operators, this is driven by the superior geology of its leasehold, combined with speed and quality of execution, from being the first to generate the play concept, lease the core acreage, drill the first test wells, and optimize operations over time to enhance rig and well productivity, and therefore, economics.

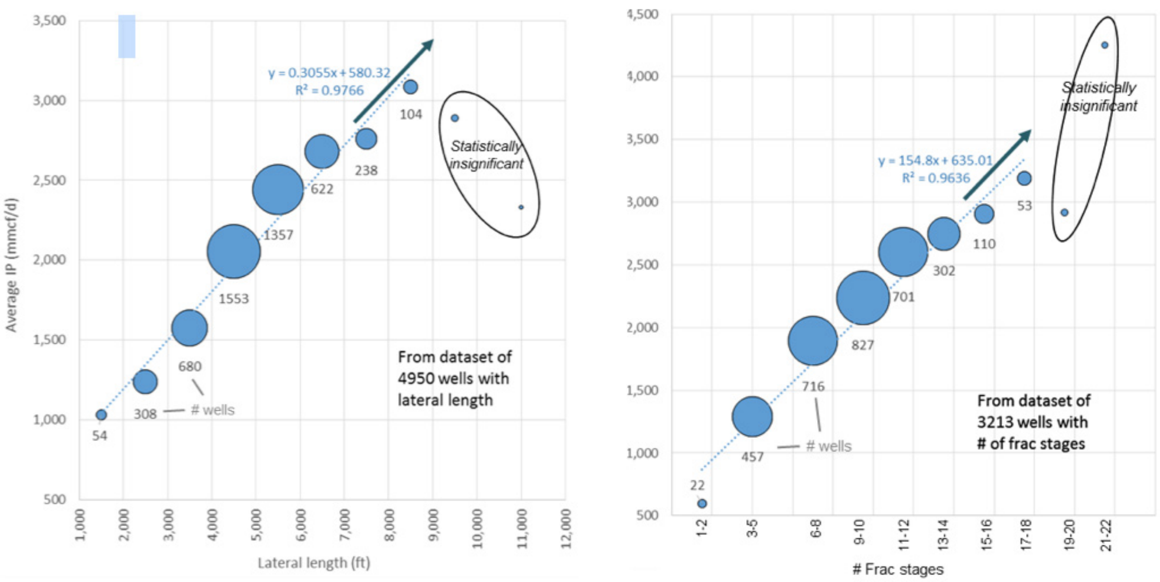
The evolution of the Fayetteville can be seen by looking at lateral length over time, with initial wells in 2004-05 having horizontal sections of 1,000-2,000' (Figure 19), but more recent wells in 2013-14 having horizontal sections of up to 12,000'. There is a positive relationship between lateral length and IP, although there is considerable scatter in the data, due to other variables that affect IP such as different operators, number of frac stages, amount of frac fluid, amount of proppant, and of course geology (Figure 20).





Figures 19 & 20: Lateral length over time and relationship between IP and lateral length (AOGC, DrillingInfo)

To reduce the scatter, we have averaged the IP for all wells of a given lateral length (e.g. 3,000-4,000'), which results in a strong positive linear relationship between IP and both lateral length and # frac stages (Figures 21 & 22). Note that the dataset for the longest laterals and greatest # frac stages is too small to be statistically significant. Additionally, although important variables, amount of proppant and amount of frac fluid correlate strongly with # frac stages, so the relationship between IP and # frac stages is assumed to capture these two other variables.



Figures 21 & 22: Relationship between IP and lateral length and relationship between IP and Frac stages (AOGC, DrillingInfo)

The bulk of wells in the Fayetteville have lateral lengths of 4,000-6,000'. Intuitively, it makes sense that IP should increase with size of completion, although this does not necessarily mean a more economic well, as the production per 1,000' of lateral may be driven more by the geology than the completion.

However, in the case of Southwestern in the Fayetteville, drilling and completion costs have been declining whilst lateral length has been increasing (Figure 23), so assuming a linear relationship between IP and lateral length, but economies of scale from larger completions, wells have been getting more economic.

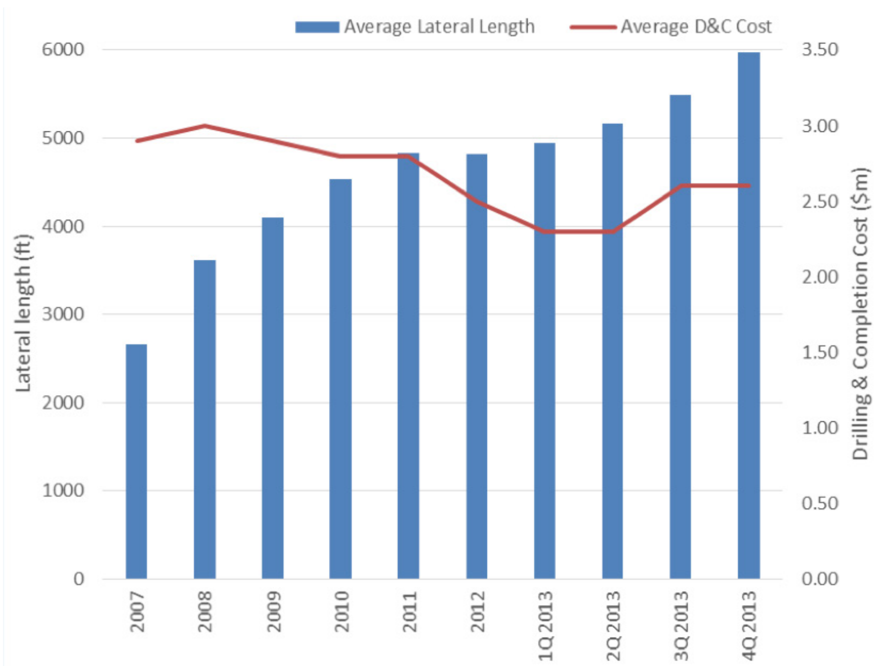


Figure 23: Southwestern Energy drilling and completion costs vs. lateral length over time (Southwestern Energy publications)

Interestingly, because the earliest wells were drilled in the core of the play, these had good IP rates because they targeted the best geology, but did not have the largest completions. In contrast, second tier areas of the play with poorer geology have become more economic overtime, as wells have become cheaper and more productive because of the larger completions. This means that a map based on IP alone may be skewed by the vintage of well. To better delineate the core of the play, we can normalize well results by taking IP per 1,000' of lateral.

This clearly delineates the geologic core of the play as southeastern Van Buren and northeastern Conway (Figure 24), with second tier areas in southern Cleburne and northern White Counties. A map of wells by operator (see Figure 25) shows that Southwestern dominates the geologic core of the play and has been responsible for developing second tier areas in southern Cleburne and the far north of White County, where recent well results have been encouraging. There is also a second tier area in central White County developed primarily by Chesapeake/BHP.

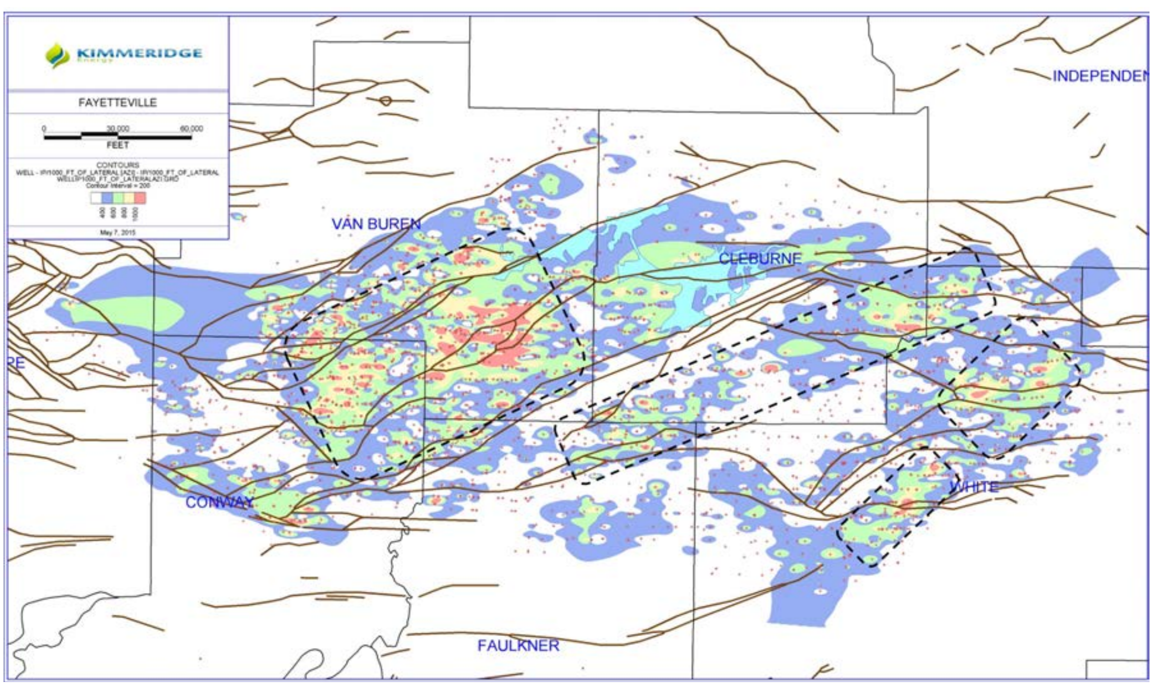


Figure 24: Contour map of Fayetteville well IP's per 1,000' of lateral (DrillingInfo, AOGC, AGS)

Notably, our estimated geologic core did not capture this second tier area in White Co., primarily due to its higher thermal maturity of around Ro 3.0%. Although well results in this area have been some of the best across the play, economics are negatively impacted by the materially higher CO2 content of these wells. Indeed, BHP have had to construct a C02 treating plant in this area, which was not necessary further west and north where thermal maturity is less than Ro 3.0% (note our cut-off for defining the core was Ro 2.0-2.5%).

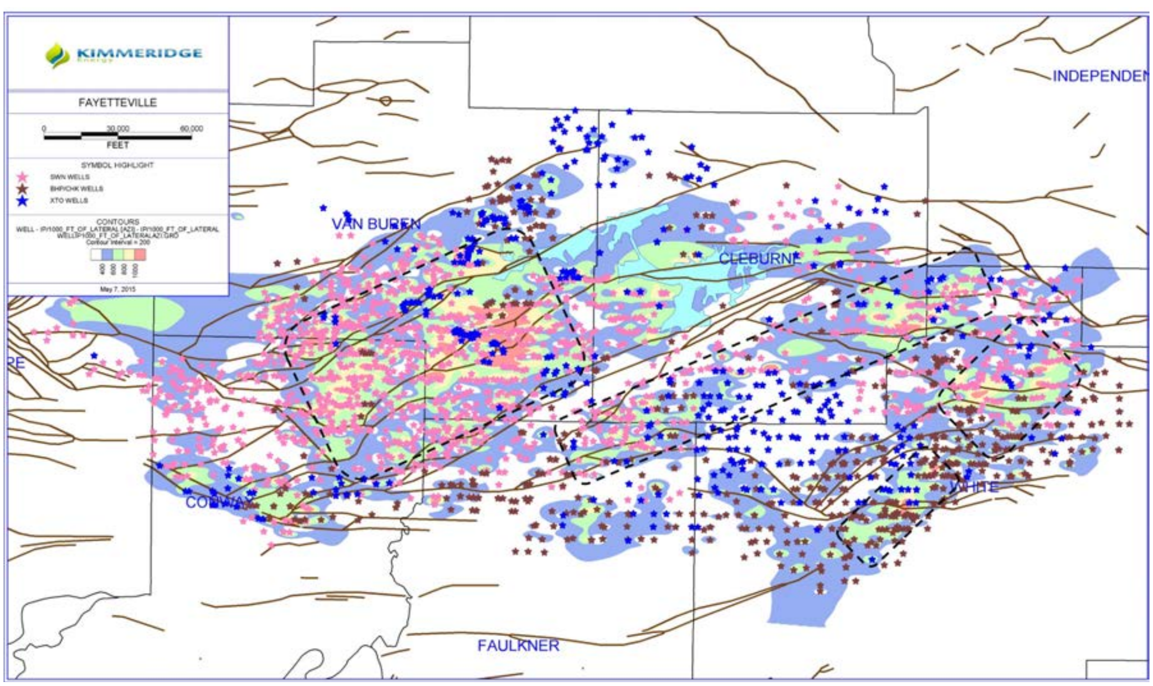


Figure 25: Fayetteville producing wells by Operator vs. IP/1,000' of lateral (DrillingInfo, AOGC, AGS)

Although we have normalized well results for completion size to better constrain the core area, this does not normalize for inter-operator variability. However, it is clear that operators other than Southwestern have seen worse drilling results, primarily because of lease positions in non-core/fringe areas of the play, and secondarily because of inferior completions. This explains why Southwestern continues to run a significant drilling program in the Fayetteville, while every other operator has stopped drilling.

Indeed, a statistical analysis of producing wells in the play clearly shows Southwestern to be the best-in-class operator. Using more than 5,000 producing wells, we have created probability density functions for IP per 1,000' of lateral, to compare operators by average performance and consistency of performance (see Figure 26). SEECO (Southwestern) have the highest average IP and the second lowest standard deviation, while BHP have the lowest average IP and lowest standard deviation. This indicates that SEECO have on average the best wells and the second most consistent drilling results, while BHP have the lowest dispersion in drilling results, but also the worst performing wells.

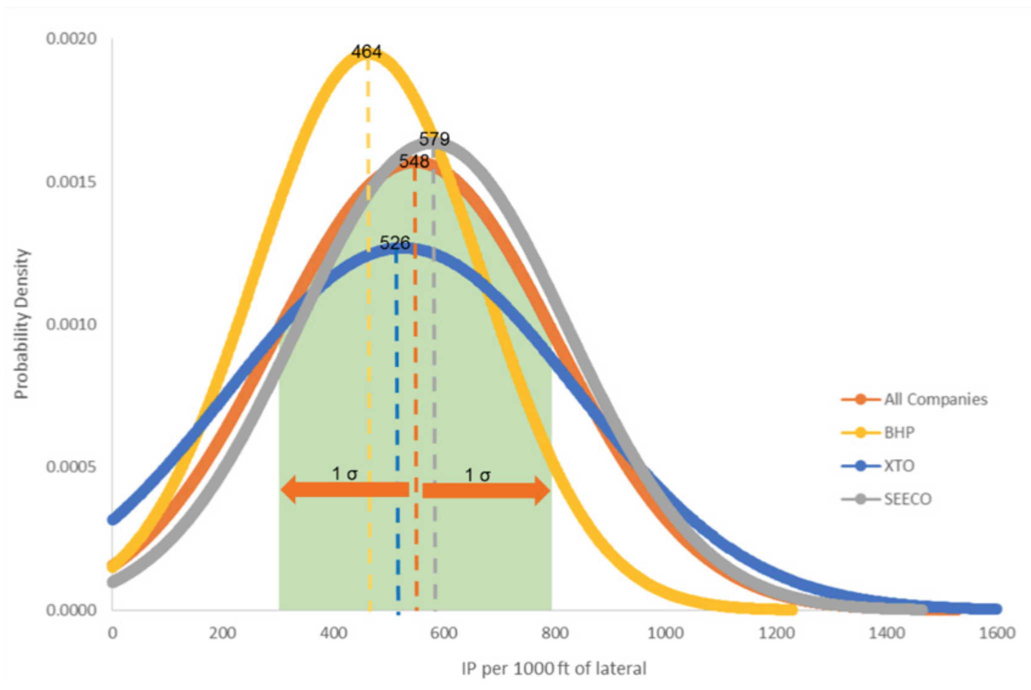


Figure 26: Probability density functions of IP per 1,000' of lateral by Operator, with mean values shown (DrillingInfo, AOGC)

Using the Coefficient of Variation, which divides standard deviation by the mean, we can see that the highest "risk-reward" operator is SEECO, followed by BHP, XTO and all other companies (Figure 27). So while XTO on average drills better wells than BHP, it has much higher dispersion, so lower overall risk-reward. Crucially, this measure does not incorporate drilling and completion costs, which would further differentiate SEECO's performance, since we believe its wells have been consistently 25-30% cheaper than competitors.

Ultimately, to compare operators' assets within the same play, we could create a risked valuation metric that incorporates the average NPV of wells, multiplied by the Repeatability Index of those wells, multiplied by the number of drilling locations. We have used the Coefficient of Variation to derive a Repeatability Index, assuming that a CV of 30% is the maximum achievable, given the large number of variables that need to be controlled in any given shale well. Given that SEECO has the most economic and repeatable wells, and also the largest leasehold, the value of its Fayetteville asset should significantly exceed that of competitors. The following section looks in more detail at the relative economics of SEECO's wells.

Operator	Mean (μ)	St. Dev. (σ)	# Producing Wells	CV = σ/μ	Repeatability Index
Max				*30%*	*100%*
SEECO	579	244	3348	42%	83%
BHP	464	205	959	44%	80%
XTO	526	315	782	60%	57%
Other Co's	316	288	27	91%	13%
Min				*100%*	*0%*
All Companies	**548**	**254**	**5116**	**46%**	**77%**

Figure 27: Mean, Standard Deviation, Coefficient of Variation (CV) and Repeatability Index by Operator (DrillingInfo, AOGC)

Well Economics

Southwestern has consistently improved its well completions over time, driving down costs whilst improving productivity. This came against a backdrop of falling gas prices and a move away from the initial geologic core of the play, making enhanced well economics even more crucial to keeping the Fayetteville at the front end of the US cost curve.

Based on published SWN capex and opex numbers, and production data from DrillingInfo, our producer well model suggests that at current gas prices of ~$3/mcf, newer SWN wells with longer laterals are break-even (see Figure 28).

We have assumed 30-day IP of 3.5 mmcf/d and EUR 2.5 Bcf. This is borne out by the fact that the company is not only drilling to HBP acreage, but continues to down-space in its core area and drill second tier areas. Notably, SWN has in recent years derived around 65-70% of production and reserves from the Fayetteville alone, with the balance coming from the Marcellus. Company profits and cashflow have therefore been highly dependent on the Fayetteville play, but this will change going forward with recent large acquisitions of Marcellus and Utica acreage.

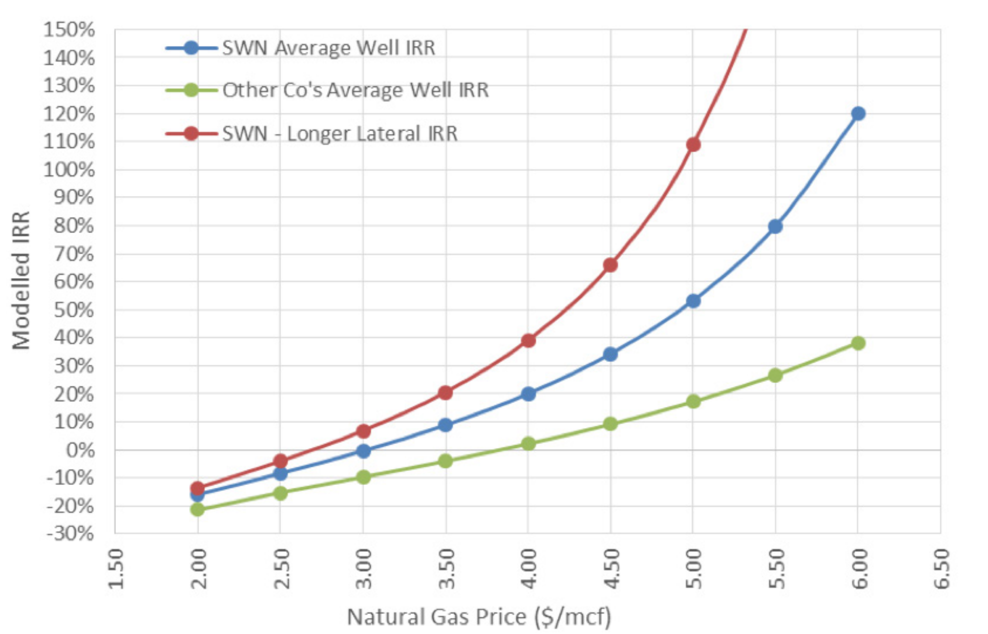


Figure 28: Modelled IRR for SWN and other companies' wells

Other companies in the play, such as XTO and BHP have had less consistent results and lower average well performance. Our well model suggests that these companies require gas prices >$4.5/mcf to make wells economic. This is supported by the fact that sustained gas prices of $3-4/mcf have resulted in both companies ceasing drilling.

Looking at the 2014 US oil and gas supply curve, we can note that SWN has a 3-year Proved Developed Recycle Ratio that is in the top quartile (see Figure 29) and driven primarily by its Fayetteville project, since this has historically provided the bulk of reserves, production and cashflow for the company. Interestingly, SWN's recycle ratio compares favorably to more oil-weighted peers, highlighting both the Fayetteville being front end of the cost curve and SWN's high quality operations.

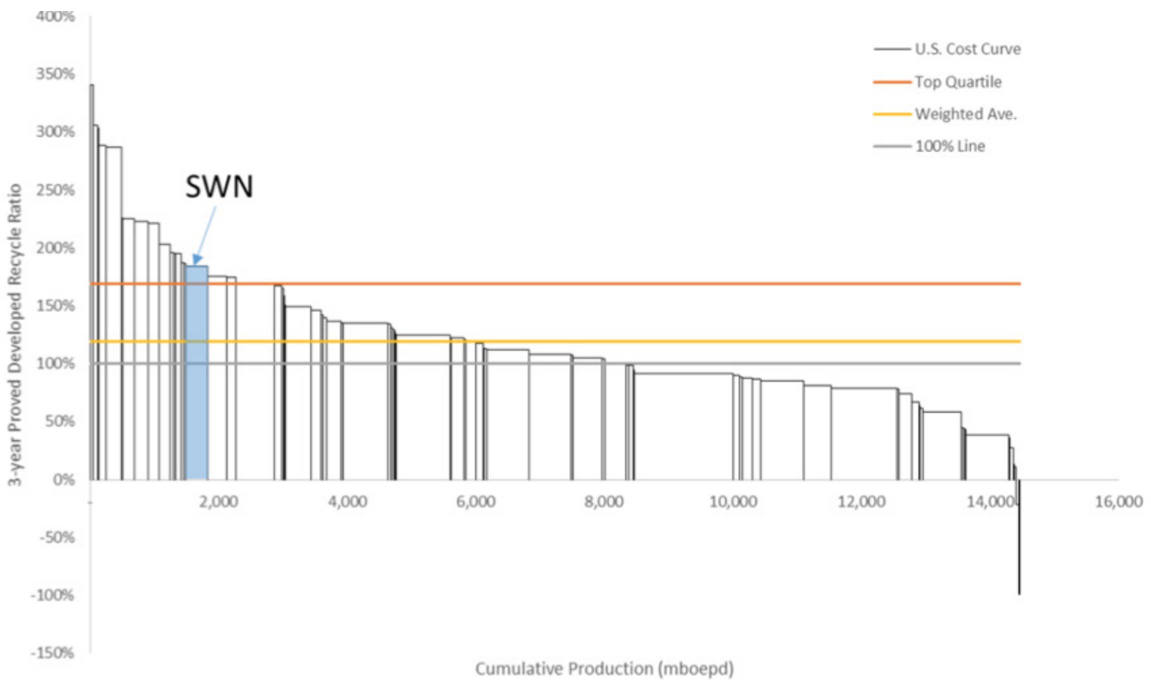


Figure 29: 2014 US oil and gas supply curve based on 3-year PD recycle ratio and production (Company Filings)

The Future of the Play

Although gas production in the Fayetteville has been very resilient in the face of sustained low gas prices, BHP and XTO have both stopped drilling and Southwestern recently slashed its 2015 CAPEX budget for the play, following its more than $5.5bn acquisitions in the Utica and Marcellus. Specifically, the company's CAPEX budget has dropped from $944M in 2014 to $560M in 2015, which represents a 41% decline. Although this is likely a near-term shift to ramp up activity in its new assets, it will impact the Fayetteville play as a whole, since we estimate that around 500 new wells per year are needed to hold production flat, whilst the new CAPEX budget from SWN (and total lack of drilling from other companies) means that only around 250-300 new wells will come online in 2015. This will almost certainly result in a drop in production.

Looking beyond the near-term to the long-term prospects for the play, there is still a huge in-place resource left to exploit. Only around 20% of recoverable resources have been produced, and with improved completions and new target intervals, there is plenty of life left in this low-cost shale play. The initial core of the play has seen fairly aggressive down-spacing, with up to 10-12 wells per section. However, we estimate that the entire core area is around 315 mi2, with around 1750 producing wells (see Figure 30), which implies around 6 wells per section on average, so there is scope to almost double the number of producing wells in this area.

Additionally, there are new second tier areas to the east of the play being opened up that have been down-spaced to around 3-5 wells per section. These areas have around 1,000 producing wells (see Figure 30), but we estimate an additional 1,500-2,000 new producing wells over time.

Looking outside of these core areas of the play, to where economics are more marginal, higher gas prices would be needed to stimulate significant drilling activity. The play itself covers >5,000 mi2, so at maximum development could have >50,000 producing wells, versus around 5,000 currently.

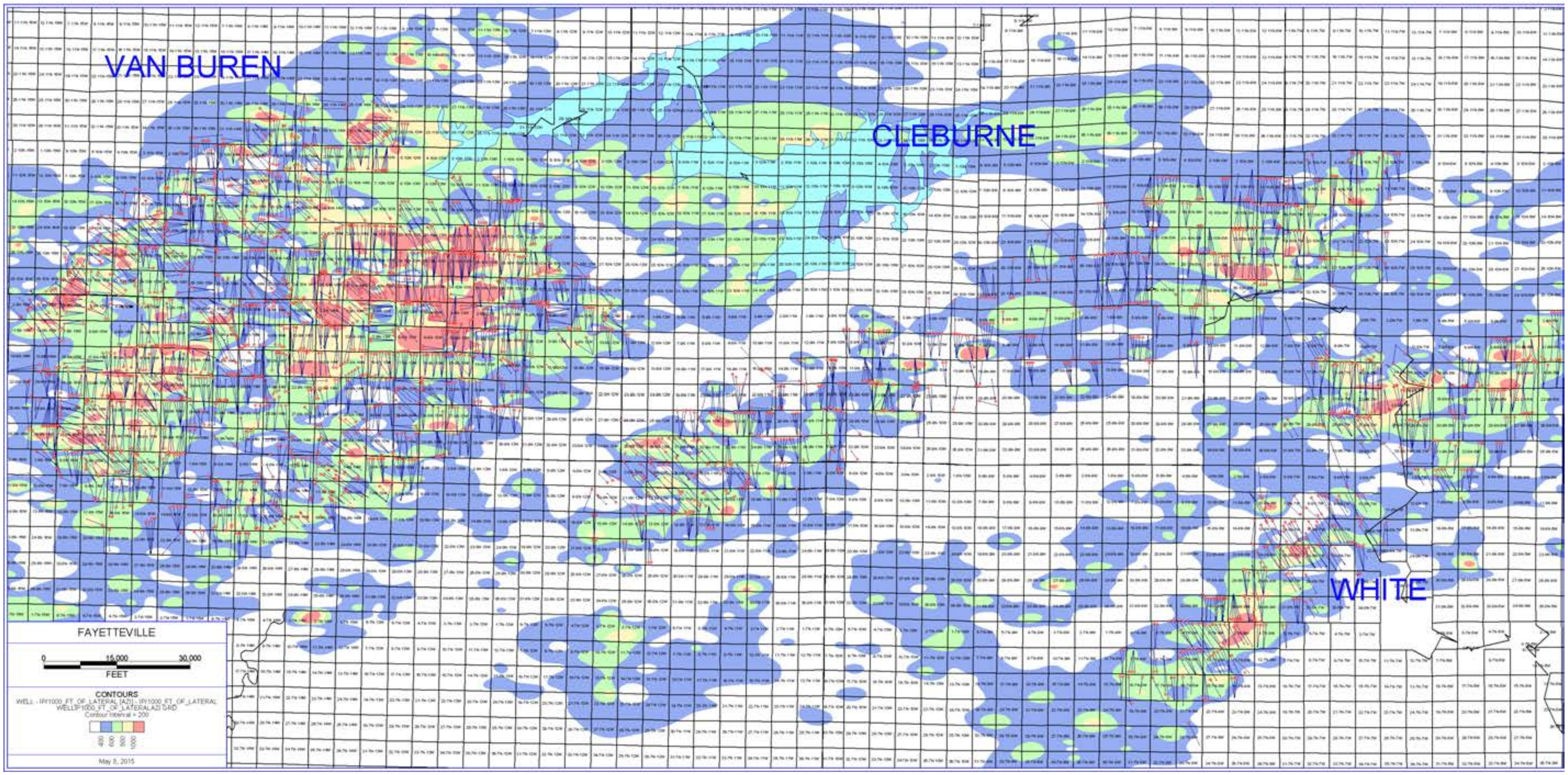


Figure 30: Core areas with wells drilled (AOGC, AGS, DrillingInfo)

Furthermore, Southwestern has been testing the Upper Fayetteville and deeper Moorefield shale as distinct target intervals, with encouraging results. This could open up 2 new benches of the play, and significantly increase the recoverable reserves. Figure 31 shows the 3 sub-units of the Fayetteville formation and the Moorefield shale:

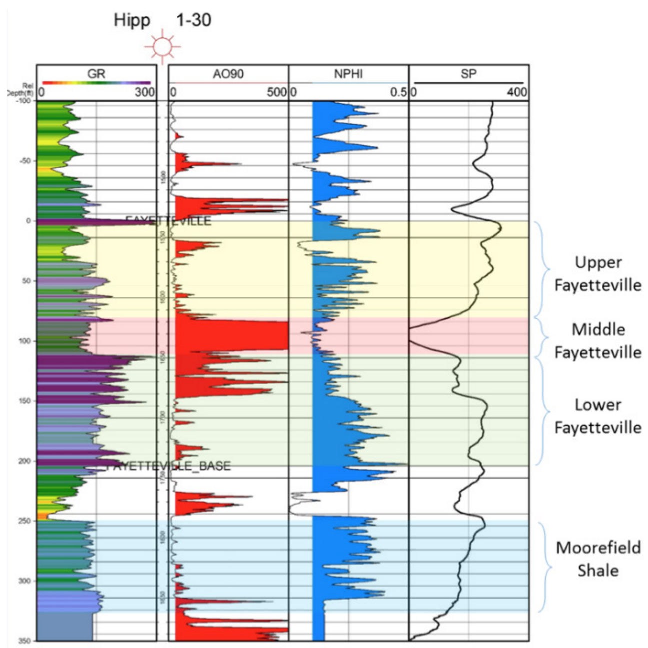


Figure 31: Type log highlighting Upper Fayetteville, Lower Fayetteville and Moorefield shale target intervals (AOGC, AGS, DrillingInfo)

The Lower Fayetteville is the "shaliest" interval, with high gamma ray throughout, good porosity (>10%) and high resistivity (indicates HC saturation). There is also a large proportion of the interval where high resistivity coincides with high porosity indicating potential pay.

The Middle Fayetteville has very high resistivity, but lower porosity and is too thin to be a distinct target interval. Nevertheless, there is a large proportion of the interval where high resistivity coincides with porosity >10%, indicating potential pay.

The Upper Fayetteville has interbedded high gamma ray shales and porosity tends to be highest with increasing shale content. There are some intervals within this unit with high resistivity and high porosity, indicating potential pay.

The Moorefield Shale has lower gamma ray than the Fayetteville, so is likely less organic-rich, but it does have good porosity, which coincides with high resistivity towards the base of the unit, indicating potential pay.

To date, Southwestern has drilled around 50 Upper Fayetteville wells, with 20 planned for 2015. An excerpt from its 3Q2014 earnings call highlights the company's plans for this new target interval:

"In the Upper Fayetteville formation, the company has placed 15 Upper Fayetteville wells online through the first 9 months of 2014, with an average production rate of 3.4 million cubic feet a day. Three of these wells had an average initial production rate of over 5 million cubic feet of gas per day, with the highest IP rate being 6.6 million cubic feet of gas per day. We plan to drill five additional Upper Fayetteville wells in the fourth quarter and complete them in early 2015. While it's early, we estimate that the Upper Fayetteville may span over 130,000 acres or 1,000 well locations for future development opportunities."

These Initial Production rates compare favorably to the Lower Fayetteville. Additionally, the company has been testing the deeper Middle Devonian Moorefield shale since 2006, albeit with a wide dispersion of results. Specifically, of the 8 wells drilled by Southwestern (all in White Co.), five had IP's <1 mmcf/d, and only one was likely economic with an IP of ~6.3 mmcf/d. Therefore, this play concept is still very much in the de-risking phase and may not prove to be a significant or economic resource.

Moving away from geological upside and focusing on operations, we expect rig and well productivity to improve going forward driven by Southwestern, which does not only include larger completions. SWN's understanding of the play is continually improving and in its 3Q2014 results the company commented that:

- extended shut-ins are being used in parts of the field with higher water content. "Some of the field has more water than other parts of the field. Extended shut-in has decreased that water," and
- the company is looking at smaller portions of its acreage in greater detail and finding some areas with good geology "that either we hadn't tested before or we hadn't tested correctly before with the procedures we're doing," (OGJ, 10/16/2014).

In summary, we believe that the Fayetteville shale gas play will see continued large-scale development by Southwestern, even at current low gas prices, although production may decline in the near term as the company re-allocates funds to develop its new acquisitions in the Marcellus and Utica. Despite this near term decline, the play has a huge amount of economically recoverable reserves yet to be developed, and there is significant upside potential in new benches of the play such as the Upper Fayetteville and Moorefield shale, as well as new areas of the play that are untested or under-explored. Additionally, we expect rig and well productivity to continue to improve – this should enhance recoverable reserves, and any increase in natural gas prices should extend the life of this highly economic play.

Summary and Key Learnings

Mature shale plays at the front end of the cost curve, such as the Fayetteville, offer us a number of important learnings that we can apply directly to exploration and exploitation of new unconventional resource plays. These are:

- In-depth understanding of both regional and local geology is necessary to generate a robust play concept
- Defining the core of the play using established geological/geochemical parameters should give an accurate indication of where the established core will be located based on well results
- A favorable regulatory environment is crucial to fostering exploration and development of the play (Arkansas has arguably the most benign regulatory regime for shale in the US)
- Early, aggressive leasing is key to establishing a core position
- Once the initial proof-of-concept wells are drilled, aggressive drilling to HBP acreage is key to maintaining a core position, since large lease positions are a rapidly depreciating asset
- Continual improvement in operational efficiency, including rig and well productivity, is vital to pushing the play to the front of the cost curve – this clearly maximizes profits and mitigates downside from lower commodity prices
- Constantly updating your understanding of the play to optimize completions and explore potential new target intervals can enhance the resource size and extend the life of the play
- Building a critical mass of operations and therefore economies of scale, can materially impact the speed of development and profitability of the play

References

1. Upper Devonian–Mississippian stratigraphic framework of the Arkoma Basin and distribution of potential source-rock facies in the Woodford–Chattanooga and Fayetteville–Caney shale-gas systems (Houseknecht et al., 2014, AAPG Bulletin, v. 98, no. 9, pp. 1739–1759)
2. Study Develops Fayetteville Shale reserves, production forecast (Browning et al., 2014, Oil and Gas Journal)
3. The Fayetteville Shale Play of North-Central Arkansas – A Project Update* (Phillip Shelby, Oct 2008, Search and Discovery Article #10172)

Notice & Disclaimer

- This document and all of the information contained in it, including without limitation all text, data, graphs, charts (collectively, the "Information") is the property of Kimmeridge Energy Management Company, LLC or its affiliates (collectively, "Kimmeridge"), or Kimmeridge's licensors, direct or indirect suppliers or any third party involved in making or compiling any information (collectively, with Kimmeridge, the "Information Providers") and is provided for informational purposes only. The information may not be reproduced or redisseminated in whole or in part without prior written permission from Kimmeridge.
- The Information has been derived from sources believed to be reliable but is not guaranteed as to accuracy and does not purport to be a complete analysis of any security, company or industry involved. The user of the information assumes the entire risk of any use it may make or permit to be made of the information. NONE OF THE INFORMATION PROVIDERS MAKES ANY EXPRESS OR IMPLIED WARRANTIES OR REPRESENTATIONS WITH RESPECT TO THE INFORMATION (OR THE RESULTS TO BE OBTAINED BY THE USE THEREOF), AND TO THE MAXIMUM EXTENT PERMITTED BY APPLIABLE LAW, EACH INFORMATION PROVIDER EXPRESSLY DISCLAIMS ALL IMPLIED WARRANTIES (INCLUDING, WITHOUT LIMITATION, ANY IMPLIED WARRANTIES OF ORIGINALITY, ACCURACY, TIMELINESS, NON-INFRINGEMENT, COMPLETENESS, MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE) WITH RESPECT TO ANY OF THE INFORMATION.
- Information containing any historical information, data or analysis should not be taken as an indication or guarantee of any future performance, analysis, forecast or prediction. Past performance does not guarantee future results. Opinions expressed are subject to change without notice.
- None of the Information constitutes an offer to sell (or a solicitation of any offer to buy), any security, financial product or other investment vehicle or any trading strategy.
- Kimmeridge Energy Management Company, LLC is a Registered Investment Adviser. Nothing herein is intended to constitute investment advice or a recommendation to make (or refrain from making) any kind of investment decision and may not be relied on as such.
- The Information has not been submitted to, nor received approval from, the United States Securities and Exchange Commission or any other regulatory body.

Contact Kimmeridge

New York
400 Madison Avenue,
Suite 14C, New York, NY 10017

London
Thornton House, Thornton Road
London, England SW19 4NG

Houston
952 Echo Lane, Suite 364
Houston, TX 77024

info@kimmeridgeenergy.com