Study Assesses Shale Decline Rates

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HOUSTON–With shale gas reservoirs producing an increasingly significant fraction of North American natural gas, and with a promising future for unconventional gas plays, it is appropriate to take a look at a large segment of the well inventory to see what can be concluded. Is there any common ground? What can the past foretell of the future? Does the industry have a tiger by the tail, or is it merely a paper tiger?

As with any emerging trend, there are skeptics. Some consultants and investment counselors question the sustainability of the unconventional gas play, with emphasis on shale gas wells' estimated ultimate recovery and overall economic feasibility.

In addition, much of the information available does not correlate because it was selected or derived using inconsistent methodologies. For example, some calculate EURs by extrapolating from initial production rates. Some have applied decline trends from one play to analyze another play.

Moreover, any two operators analyzing the same prospect will come up with different answers. Different operators use different rules, and since each operating company must base its business decisions on its own economic status, it is little wonder that predictions are all over the place.

To examine the history of any era or series of events, one must have a statistically significant database. One or two points do not define a trend. Accordingly, the portion of a shale gas production decline rate study detailed in this article is limited to examining wells in the Barnett, Fayetteville, Woodford and Haynesville plays.

Besides examining decline curves in detail to try to identify trends or common ground, the study attempted to identify any correlation between production improvements and implementing new technology or techniques. In addition, the decline trends of both horizontal shale gas wells and horizontal tight gas sandstone wells were compared, looking for similarities and any refinements on the ability to predict EUR. To provide a common denominator, the analyses were conducted through break-even economics using a P50 probability case to put everything into a dollars and cents basis.

The exercise was nontrivial. In all, 1,957 horizontal shale gas wells were included in the portion of the study referenced in this article, before quality assurance/quality control was applied to the data. Other well known fields were considered for the purposes of general comparison. Field lives varied from a mature Cotton Valley play with almost 30 years of production history to some of the most recent shale plays, such as the Eagle Ford.

Decline Curve Analysis

One of the biggest challenges is the methodology to determine EUR. Techniques vary from material balance to numerical simulation, and decline curve analysis or volumetric analysis to analogy. Each has its attractions, but each also has its caveats. Since decline curve analysis is relatively simple and expedient, it was used.

The study was limited to wells with publicly available data. Wells were chosen from a geographic area representing a core area within each shale play and that had the longest productive history for the play. Wells with a normal decline trend, no matter how good or bad, were included.

Typically, only production and completion data were recorded, leaving out geophysical, petrophysical and geomechanical properties. Any wells that looked likely to be refracs and whose data impacted the resulting type curves were removed. Less than 16 percent of the wells were excluded from the analysis. Following this initial QA/QC process, the final well count was 1,931, including 46 Eagle Ford wells.
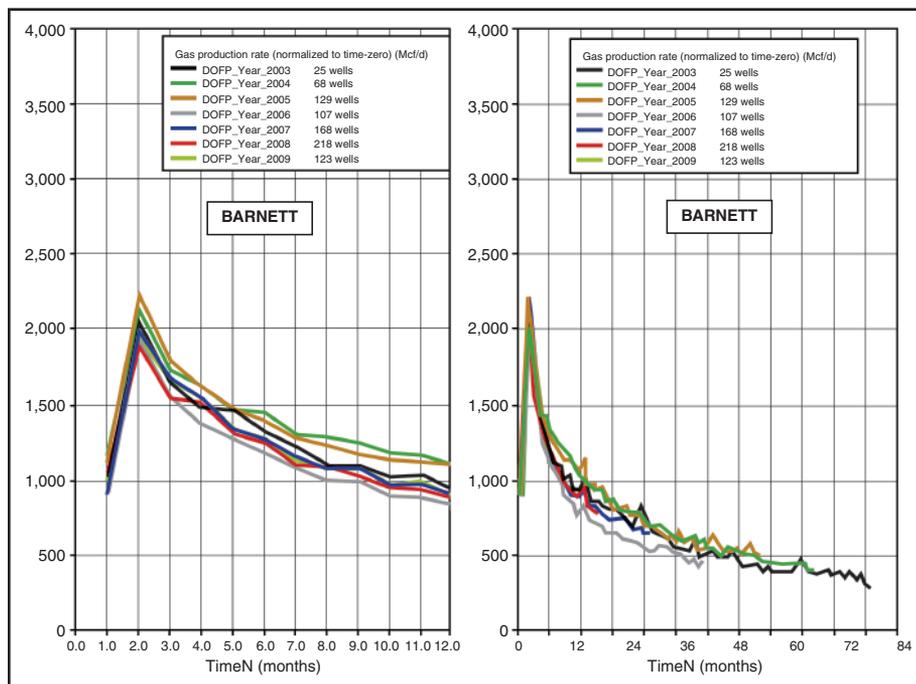
Wells in each study were time-shifted so that each was assumed to have identical "day one" dates, labeled date of first production (DOFP). For example, when the oldest well in a basin went on line, that date was established as time-zero, and all subsequent wells for that year had their DOFPs shifted to the same time-zero date so that the production data on all wells had the same starting date.

Monthly data from each well were divided by the number of days in the month to obtain the average daily production rate for the month. The daily rates for all the wells in a particular calendar group were averaged to obtain P50 well production for the stated data rate. Statistical accuracy was maintained by tossing any DOFP group that had fewer than eight wells.

A final quality assurance step was taken after it was observed that a sudden drop or increase in the active well count for a given calendar year could materially

FIGURE 1

Barnett Shale First-Year and Total Production Rates
Color-Coded by Year

In Arp's decline curve analysis, there exists a so-called b factor that relates to the curvature of the decline trend, and therefore, must be considered in any curve-fitting technique used to fit the resulting decline curve to a production rate versus time plot. If b equals 0, an exponential decline curve results and the calculated decline rate is constant. The study of horizontal shale gas wells revealed significant variations in the b-factor, from a low of 0.6377 in the Fayetteville to a high of 1.5933 in the Barnett.

There is some unease in the industry about b factors greater than 1.0; however, a look at 30 years of data from 445 Cotton Valley vertical tight gas wells yielded a b factor of 1.2778, adding a sense of reasonableness to the answers.

Study Results

Figure 1 shows average daily production rates per well for Barnett horizontal shale completions in the core North Texas counties of Tarrant, Wise, Denton and Parker. On the left is the initial 12 months of production for the 838 wells grouped by completion year, while the entire production history is on the right. Colors represent years that the wells were brought on stream, normalized using shifted DOFPs from 2003 through 2009. The production

affect the decline curve. The major cause of this anomaly was found to be wells that came on stream in the latter months of the year. For example, wells whose DOFP was January 2007 had 38 months of production data when the study was terminated, but wells with a December 2007 DOFP (also grouped with the 2007 wells) would only have 27 months of production. This could have impacted the results, so it was taken into account in the analysis.
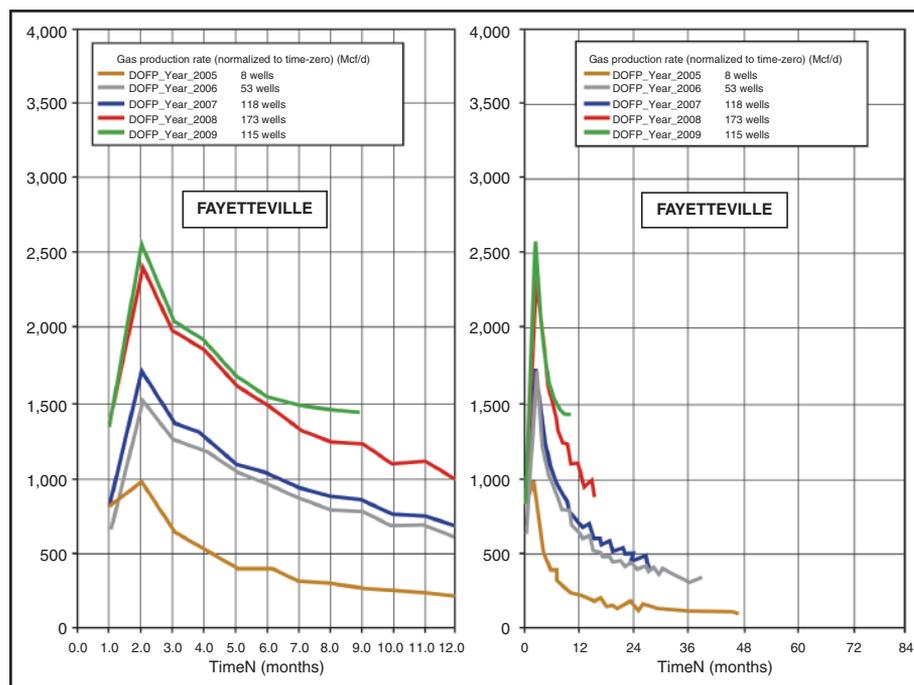
Representative Wells

After all quality checks had been implemented, there remained a total of 1,885 representative wells in the study: 838 from the Barnett, 467 from the Fayetteville, 305 from the Woodford, and 275 from the Haynesville.

Decline curve analysis was performed using the Arp's equation, even though this approach is more appropriate for conventional reservoirs with vertical wells where boundary-dominated flow is the norm. Nevertheless, the well known and accepted Arp's equation was deemed the best available approach. The study utilized an "auto decline" functionality from production analysis software, and was performed on data from each basin with careful consideration of whether to include outlying data points to avoid subjectivity. The final

production type curves used historical decline curve regression instead of actual production data. This approach yielded smoother results that facilitated comparing different basins and calendar years.

FIGURE 2

Fayetteville Shale First-Year and Total Production Rates
Color-Coded by Year

FIGURE 3

Woodford Shale First-Year and Total Production Rates
Color-Coded by Year
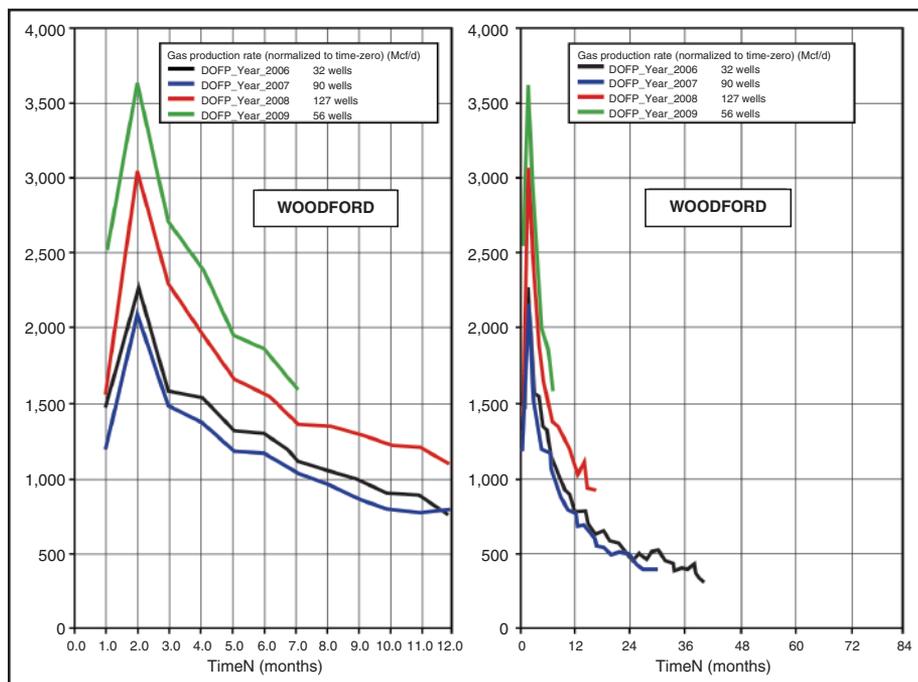
profiles are remarkably consistent, even though the average number of fracture stages pumped increased from two to six over the time frame.

Completion and stimulation treatments have changed slightly from a majority of slick-water fracs to some use of cross-linked polymers in hybrid treatments, but no clear advantage of one technique over another can be concluded from the data. The formation surface curvature and open natural fractures may act in tandem to dictate the ultimate hydraulic fracture geometry, reducing the impact of hydraulic fracture size, staging and design.

A completely different story is revealed by Fayetteville horizontal shale completions from 467 wells in Conway and Van Buren counties in Arkansas, where steady year-on-year improvement can be seen (Figure 2). In this case, the improvements are attributed to a dramatic increase in lateral length and number of stages treated per well. During the study period, fluid volume doubled and proppant volumes tripled per well.

In Oklahoma, the 305 Woodford Shale wells in sections of Hughes and Coal counties showed a similar improvement to the Fayetteville. Primary reasons were increased lateral length and number of stages pumped (Figure 3).

The 275 Haynesville Shale play wells

included in the study are located in Bienville, Bossier, Caddo, Desoto, Red River and Sabine parishes in Louisiana. As illustrated in Figure 4, marked improvement was observed after a modest beginning. Similar to Fayetteville and

FIGURE 4

Haynesville Shale First-Year and Total Production Rates
Color-Coded by Year
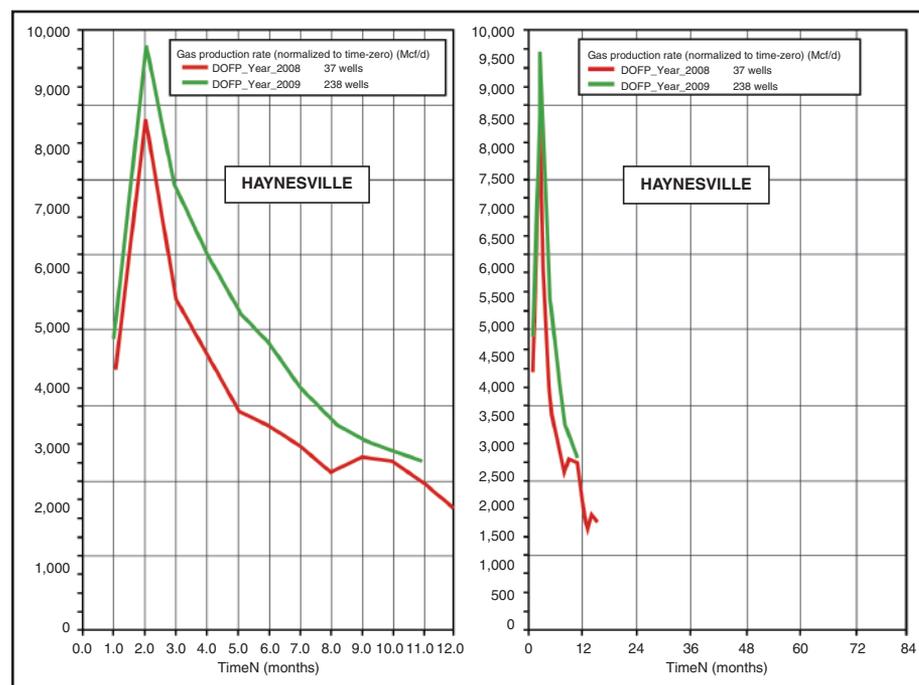
Woodford wells, improvements were attributed to increased lateral length and number of stages pumped.

The stimulation volumes also evolved proportionally to lateral length, more so than other shale plays. The Haynesville has the highest production rate, mainly because its reservoir pressure is greater. Another cause for the increase could be more stages with greater fluid and proppant volumes per stage.

Lessons Learned

Lessons learned from earlier analyses of shale plays are benefiting the later developments in terms of improved log and core evaluation, leading to more precise well placement in reservoir sweet spots as well as better completion and stimulation design. Improvements have been made in lateral length, stage selection, diverter use and pumping techniques. Real-time microseismic hydraulic fracture mapping has enabled operators to avoid geohazards while maximizing reservoir contact.

While the Barnett Shale has the lowest initial production compared with the other plays, the decline rate for Barnett wells is markedly flatter, leading to the conclusion that fracture conductivity is sustained longer in the Barnett because of the favorable rock properties. However,

a large number of open natural fractures in this area characterize the Barnett Shale.

With this wealth of data, any number of comparisons can be made to determine if there are relationships among basins, production years, initial production rates or decline rates. This allows EUR forecasts to be made.

It is perhaps an unfair comparison, but when shale gas wells are compared with tight gas sands wells, and when vertical wells are compared with horizontal wells, in a general sense it is clear that horizontal shale gas wells offer significantly higher EURs–definitely when compared with vertical wells, but also when compared with tight gas sands horizontal wells. The normalized decline curves were similar for both horizontal shale gas and horizontal tight gas sands, if not slightly better for the shales.

For the time frame analyzed, the Cotton Valley sand is a lower limit for normalized production decline behavior for all commercial horizontal shale gas plays analyzed in the study (Table 1). Considering that the study was conducted using only publicly available data, and did not include production improvements from workovers, recompletions or refracs, one can conclude that the study results are likely on the conservative side.

Costs Versus Gas Prices

Bottom-line financial success in the shale plays depends on many things, not the least of which is the capital cost of leasehold acquisitions. Early entrants have a decided advantage, some paying one-tenth of the lease prices of latecomers. Different basins have exhibited decidedly different cost structures (Table 2), which impact the economic parameters. Consequently, differences were factored into the economic analysis by determining discount profitability indexes (DPI) to allow basins to be compared. For this analysis, well construction, royalty and operating costs were compared with the EUR at three discount rates, assuming a constant wellhead gas price of $4.00 an Mcf for the life of the well (Table 3). Profitability is defined for wells whose DPI is greater than 1.0 at a given discount rate.

Accordingly, for wells analyzed in core play areas in 2008 and 2009, only wells in the Barnett and Fayetteville were deemed to be profitable under spot gas prices. That said, it is important to note that many operators have some or all of their gas prices hedged at higher than spot price values. However, it also is

TABLE 1

Decline Curve Analysis Results Comparing Typical Shale Gas With Tight Gas Plays (Vertical and Horizontal Completions)

Case	Reservoir Type	Well Type	History	Total Wells	EUR@ 30Years	b	Di	Cummulative Gas Production
			Months	#	MMcf	–	M.n	MMcf
Barnett	Shale Gas	Horizontal	64	731	2,989	1.5933	0.0089	1,415
Fayetteville			37	467	1,390	0.6377	0.0325	883
Woodford			45	305	1,696	0.8436	0.0227	996
Haynesville			12	275	5,915	1,1852	0.0632	1,740
Eagle Ford			7	59	3,793	1,694	0.0826	548
Cotton Valley	Tight Gas Sandstone		48	96	1,926	0.7259	0.0248	1,341
Cleveland			60	388	824	1	0.0149	478
Cotton Valley (1980)		Vertical	354	445	2,703	1.2778	0.0021	2,703
Cleveland (1980s)			195	967	676	2.3483	0.0022	476
Cotton Valley (>2005)			48	4401	940	1	0.0175	469
Barnett (1980s)	Shale Gas		108	56	742	1.9366	0.0046	389

TABLE 2

Differences in Well Cost, Royalties Paid and Operating Cost

Play	Well Cost ($MM)	Royalty (%)	Operating Cost ($/Mcf)
Haynesville	8	25	2.5
Eagle Ford	5.8	25	1.5
Barnett	3	22	0.7
Fayetteville	2.8	17	1.1
Woodford	6.7	19	1.15

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TABLE 3

Case	Before Tax @ $4/Mcf				
	DPI @ 0%	DPI @ 10%	DPI @ 15%	ROR, %	EUR, Bcf
Barnett_DOFP_2008	2.11	1.11	0.92	12.6	2.895
Barnett_DOFP_2009	2.09	1.1	0.92	12.3	2.867
Fayetteville_DOFP_2008	1.95	1.15	0.99	14.7	2.463
Fayetteville_DOFP_2009	2.69	1.43	1.19	22.1	3.401
Woodford_DOFP_2009	0.71	0.42	0.37	0	2.544
Woodford_DOFP_2008	0.94	0.53	0.45	0	3.389
Haynesville_DOFP_2008	0.29	0.19	0.16	0	4.579
Haynesville_DOFP_2009	0.38	0.24	0,21	0	6.092
Eagle Ford_DOFP_2009	0.83	0.45	0.38	0	3.793

Discount Profitability Index at Three Discount Rates

TABLE 4

Break-Even Price by Shale Gas Basin

Case	EUR, Bcf	Gas Price (DPI @ 10% = 1)
Barnett_DOFP_2008	2.895	3.7
Barnett_DOFP_2009	2.867	3.74
Fayetteville_DOFP_2008	2.463	3.65
Fayetteville_DOFP_2009	3.401	3.2
Woodford_DOFP_2008	2.544	7.35
Woodford_DOFP_2009	3.389	6.22
Haynesville_DOFP_2008	4.579	6.95
Haynesville_DOFP_2009	6.092	6.1
Eagle Ford_DOFP_2009	3.793	6.24

clear that modern methods and technology supported by experience and knowledge are improving results significantly in most plays. The results shown in Table 4 reflect the break-even price for wells drilled in each formation based on wells completed in 2008 and 2009.

It is important to note that actual drilling, completing, stimulating and operating costs may vary greatly from operator to operator, resulting in a large impact on overall economics. Some operators may have better production in a given core area versus others, further improving the picture. In addition, as noted, nearly all operators have at least some portion of their gas prices hedged at levels that may make all or most of the shale plays analyzed viable. ❒

Editor's Note: For more detailed information on the results of the shale gas production decline study and trend comparisons over time by basin, see SPE 135555, a technical paper presented at the Society of Petroleum Engineers 2010 Annual Technical Conference & Exhibition in Florence, Italy