AN INVESTOR'S GUIDE TO SHALE GAS

A SUPPLEMENT TO

Oil and Gas Investor

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SHALE SIZZLES

A *New York Times* article reported last October that in Fort Worth, Texas, along Interstate 30, a billboard advertises, "If you don't have a gas well, get one!"

Yes, gas shale plays are now attracting national media attention, not to mention some 64 public E&P companies now report some involvement in at least one shale play. Shales are creating a booming business.

More than 100 rigs are running in the Barnett Shale around Fort Worth, with some eye-popping lease bonuses being paid—even right underneath the Dallas-Fort Worth airport and Lake Arlington. The Barnett alone is producing about 2 billion cubic feet per day, making it the largest gas field in Texas and a major contributor to U.S. gas production.

A pattern of intense—some would say frantic and stealthy—leasing showed up in the Fort Worth Basin's Barnett Shale in 2003, spread to the Arkansas Fayetteville Shale in 2004 and 2005, then moved to Oklahoma's Woodford, to a Barnett-Woodford look-alike in Far West Texas, and now, is moving to Alabama and Appalachia.

The value of developed gas shale assets was dramatically illustrated last spring when Chief Oil & Gas LLC of Dallas went for $2.15 billion to Barnett Shale leader Devon Energy Corp. The latter estimates at least 800 more drilling locations from this deal.

The good news continues. In November, EOG Resources pleased investors by raising its net Fort Worth Basin Barnett resource potential by nearly 45%, which could double the amount it has booked for all of North America. A big reason is the company's "southern extension" area south of the so-called core, especially in Hill County. EOG estimates its net potential there is at least another 1 trillion cubic feet equivalent.

Also last fall, Newfield Exploration and Southwestern Energy reported surging production, higher reserves per well and increased drilling in their Woodford Shale and Fayetteville Shale plays, respectively.

With results like these, no wonder investors want to know more about all the shale plays throughout the U.S. Greater understanding is invaluable. This special report will provide information about all these plays, whether they are established ones rapidly growing or emerging ones attracting new drilling. You'll get an update on all the players involved, and you'll learn more about the special technologies involved, as well as the decision-making hierarchy required.

—Leslie Haines, Editor-in-Chief

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About the Cover: Earlier this year, XTO Energy's Carter B No. 1-H was fractured by Frac Tech near Eagle Mountain Lake in Tarrant County, Texas. (Photo by Lowell Georgia)

THE SHALE SHAKER

With gas at $6 per MMBtu, operators can't, and won't, stop pursuing shale-gas plays. The number of companies involved is growing.

By John White and Roger Read, Natexis Bleichroeder Inc.

The past 12 months have seen several exciting developments in U.S. shale plays. As more E&P companies get involved, shale-gas production continues to climb and frac techniques continue to advance.

The list of companies pursuing shales continues to grow. Our first report on shales in November 2005 showed 23 publicly traded companies involved in shale-gas plays. In June 2006, we tallied 39. We now find 64 publicly traded entities. We are certainly missing some because of the sheer magnitude of activity and the fact that companies sometimes hold leases in third-party names to maintain secrecy (Table 1).

Newfield Exploration Co. appears to have cracked the code on the Woodford Shale in Oklahoma, as evidenced by significantly higher initial flow rates on a string of well completions in late 2006.

The core area of the leading shale, the Barnett Shale around Fort Worth, still takes first place in terms of rates of return, with Tier 1 Barnett and the Woodford now in a virtual tie for second place. The Fayetteville Shale in Arkansas is running a close third with Southwestern Energy Co. the most active driller there.

Meanwhile, the emerging Barnett-Woodford play in Far West Texas appears to have turned in mixed results to date. So far, some wells in this area have been difficult to drill and complete. One industry source said one recent well (unnamed) reportedly came in with a completed well cost of $16 million.

Gas Shale Economics

Our updated economic model reflects the changes in reserve, production and cost profiles for the most advanced shale plays: the Barnett, Fayetteville and Woodford.

We expect natural gas prices to average about $7 per MMBtu in 2007. The major shale plays show robust economics at a lower price, $6 per MMBtu (Figure 1). Given the weakness experienced in U.S. natural gas prices during third-quarter 2006, we looked at the economics of these plays under lower gas price assumptions. We ran our downside cases at $4.50 per MMBtu.

	Base Case $6/MMBtu Henry Hub	Downside Case $4.50/MMBtu Henry Hub
	After tax rate of return	After tax rate of return
Barnett Core	131%	57%
Barnett Tier 1	59%	8%
Barnett Non-core	32%	-10%
Fayetteville	51%	7%
Woodford	61%	13%

Figure 1. *Gas Shale Economics Summary. Source: Company reports, Natexis Bleichroeder Inc. estimates. Note: Most values vary locally within each play.*

Under our expectations of gas prices for 2007, we believe that rig dayrates have peaked.

The variability within each play and between operators deserves mention. Wells in the core area of the Barnett Shale can range between 2.5 billion cubic feet equivalent (Bcfe) to 5 Bcfe of reserves. We are using 3.5 Bcfe for the Barnett core, 2.2 Bcfe for wells in the Tier 1 areas and 1.0 Bcfe for the non-core areas of this play. There are also definitional differences in how each company divides up the areas of the play. Some companies use the terms Core 1 and Core 2, while others use Core and Tier 1.

In a sustained gas price environment of about $4.50 per MMBtu, operators would more strictly prioritize drilling prospects assuming current rig rates and oilfield service costs.

Under our analysis, the core area of the Barnett Shale will remain a high priority for drilling. The Barnett area referred to as Tier 1 would likely experience a slowdown in activity, though at a 20% average rate of return, selected individual well locations would continue to be drilled, in our opinion. The western and southern edges of the play, the so-called non-core areas, would likely see a dramatic drop in drilling activity as returns become negative.

Woodford Shale

This play, situated in the Arkoma Basin in southeastern Oklahoma, is starting to come on strong. Recent results point to a complete step-change in the reserve and production expectations. The industry has been pursuing gas-shale production here since early 2003. Companies active in the Woodford include the pioneer of the play, Newfield Exploration Co., as well as Chesapeake Energy, Devon Energy, XTO, Petrohawk Energy Corp. and St. Mary Land & Exploration.

As with all of these shale plays, there is the initial drilling and completion effort, followed by several rounds of using different drilling and completion techniques, together with better subsurface imaging. Each play is unique in terms of best drilling and completion practices.

Newfield appears to have learned much about the Woodford, given its series of recent well completions there. Initial flow rates are significantly in excess of previously completed wells. Recent horizontal drilling results have been strong compared with wells completed earlier in 2006. The recent success is partly because of increased fracture densities, such as more frac stages per wellbore.

The new wells show significantly higher initial peak production rates and subsequent post-peak production rates (Table 2).

In addition to improving the design of its fracs,

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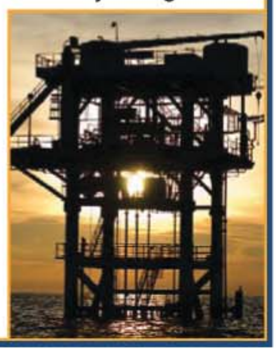

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Table 1. *A sampling of public companies report activity in a number of shale plays.*

Large, Mid and Small-Cap Company	Ticker	Estimated Net Acreage in Gas Shale Plays (thousands)	Shale Plays Barnett	Fayetteville	Woodford	Devonian/ Ohio	Barnett/ Woodford	Floyd	New Albany	Mowry	Gothic	Bakken	Baxter
Abraxas	ABP	64					•			•			
American Oil & Gas	AEZ	NA								•			
Anadarko Petroleum	APC	NA	•			•	•						
Apache	APA	NA	•										
Bill Barrett	BBG	NA									•		
Brigham Exploration	BEXP	130	•							•		•	
Cabot Oil and Gas	COG	NA				•					•		
Carrizo Oil and Gas	CRZO	309	•	•			•	•	•				
Chesapeake	CHK	1,665	•	•	•	•	•	•	•				
Chevron	CVX	NA					•						
Clayton Williams	CWEI	NA					•						
ConocoPhillips	COP	500	•				•						
Contango Oil and Gas	MCF	48		•									
Denbury Resources	DNR	50	•					•					
Devon Energy	DVN	1,132	•		•		•						
Dominion E&P	D	NA				•							
Edge Petroleum	EPEX	38		•				•					
El Paso	EP	NA							•				
EnCana	ECA	745	•				•		•		•		
Encore	EAC	27	•				•						
Energen Corporation	EGN	100						•					
EOG Resources	EOG	NA	•		•	•		•	•				
Equitable Resources	EQT	NA				•							
Exploration Company	TXCO	NA											
ExxonMobil	XOM	NA	•				•						
Forest Oil	FST	65	•						•				
Infinity	IFNY	60	•										
Marathon Oil	MRO	NA	•									•	
Murphy Oil	MUR	NA						•					
Newfield Exploration	NFX	115			•								
Noble Energy	NBL	175		•				•	•				
Parallel Petroleum	PLLL	61	•										
Penn Virginia	PVA	85		•		•			•				
Petrohawk Energy	HAWK	23		•	•								
Petroquest	PQ	25			•								
Pioneer Natural Res.	PXD	NA					•						
Pogo Producing	PPP	168	•						•			•	
Questar	STR	NA											•
Quicksilver	KWK	575	•				•		•				
Range Resources	RRC	350	•			•	•						
Shell	RDS-B	NA	•	•									
Southwestern	SWN	1,361		•	•		•						
St. Mary Land	SM	114			•							•	
Storm Cat	SCU	13		•									
Talisman	TLM	NA				•							
Williams Co	WMB	94	•								•		
XTO Energy	XTO	435	•	•	•		•						

Micro-cap Companies	Ticker	Estimated Net Acreage in Gas Shale Plays (thousands)	Shale Plays Barnett	Fayetteville	Caney/ Woodford	Devonian/ Ohio	Barnett/ Woodford	Floyd	New Albany	Mowry	Gothic	Bakken	Baxter
Altai Resources	ATI.V	NA											
Ascent Resources plc	ACTPF	NA				•							
Crimson Exploration	CXPO	NA					•						
Dune Energy Inc	DNE	3.7	•										
Hallador Petroleum	HPCO	NA							•				
Ignis Petroleum	IGPG	6.9	•										
Lexington Resources	LXRS	5.0	•										
Morgan Creek Energy	MCRE	0.1	•										
Nitro Petroleum Inc	NPTR	7.0	•										
Nova Energy	NVNG	NA	•										
Petrosearch Energy	PTSG	4.2	•										
Pilgrim Petroleum	PGPM	NA	•										
Questerre Energy	QEC	NA											
TBX Resources	TBXC	2.8	•										
Unicorp Inc	UCPI	7.6							•				
US Energy Holdings	USEH	NA					•						
Westside Energy	WHT	17.2	•										

Notes: The Bakken is an oil producing shale. Source: Company reports.

Newfield has highlighted the differences in the rock itself. One of the important characteristics is the mineralogy, specifically the silica content. The silica content adds aspects of porosity closer to a sandstone or chert, compared with most other shales (Figure 2). The Woodford delivered good economics prior to the release of the results from recent wells completed in November 2006 (Table 3).

Assuming a gas price of $6 per MMBtu, the after-tax return is 61%, but if using a gas price of $4.50 per MMBtu, the returns drop to about 13%. The latter is probably a low enough level that companies would decrease drilling in the play and focus only on high-graded prospects.

Should the completions reported in November 2006 prove to be the new "type well" or average for the Woodford play, the economics would dramatically change. We ran the economics again using a higher production rate of 5 million cubic feet equivalent (MMcfe) per day with the result being a 170% after-tax rate of return.

We would point out another potential advantage the Woodford has versus the Barnett is its uphole zones that offer additional production potential. The Caney, Cromwell and Wapanuka zones all have produced in the region in other fields and wellbores.

Barnett Shale

This play continues to deliver exceedingly strong results. Production increased by 25% during the first six months of 2006 compared with 2005, according to the Texas Railroad Commission. The commission's preliminary figures, which have tended to be understated until more complete reports are submitted, showed production of 282 Bcfe during the first six months of 2006, compared with 224 Bcfe during the same six months in 2005.

Based on figures supplied by active operators in the play, we believe current gas production is between 1.8 and 2.1 Bcfe per day.

The field now has about 5,900 producing wells, of which about 23% are horizontal completions. Activity continues at a strong pace with about 160 rigs running.

Returns vary between the core area, Tier 1 and the non-core area, with possible returns ranging from 131% in the core area to only 32% in the non-core. Well costs are higher in the core, but gross reserves per well are also higher.

As the core area has developed, certain operational issues are arising:

- turnover of the type and vintage of rigs being used;
- tightness of supply for pressure pumping equipment and crews;
- water access; and
- well permitting and city ordinance issues.

Our discussions with operators have indicated that rig rates have gone flat since May 2006 because of weakness in gas prices and increased supply of land rigs. The turnover of the type and vintage of rigs is positive for the Barnett play and other plays.

The land drillers have responded to the tightness in the market experienced in 2004 and 2005, bringing new and significantly refurbished/upgraded equipment to the market. The new upgraded rigs offer substantial performance improvements.

As older rigs are displaced, they are moving into the Woodford play in eastern Oklahoma and the Fayetteville play in western Arkansas.

Given the size of the Barnett play and the diverse set of operators and operating practices, the rigs in the play fall into three broad categories based on horsepower. Current rates for these rigs range between $18,000 and $22,000 per day. As the newer rigs move into service, we will probably see the lower horsepower and lesser depth capacity rigs move firmly into the lower end of the range of rates and the higher capability rigs firmly into the higher end of the range.

Reservoir Traits	Barnett	Woodford
State(s)	Texas	OK
Basin	Fort Worth	Arkoma
Geologic Age	Mississippian	Mississippian
Depth (feet)	7,200 - 9,000	6,000 -12,000
Thickness (feet)	300-500	120-220
Reservoir pressure (PSI)	3,000 - 4,000	3,000 - 5,500
SCF/ton	100-150	150-225
Gas in place (Bcf/sq. mile)	50 - 200	40-120
Total organic content (%)	4.0 - 8.0	3 - 10
Thermal maturity (Ro)	0.7 - 3.0	1.1 - 3.0
Silica content	40% - 60%	60% - 80%

Figure 2. *Comparison of selected gas shales. Source: Company reports, Ryder Scott, USGS, Natexis Bleichroeder Inc. estimates.*

The tight supply of pressure pumping equipment comes from two factors. First, the rig count in the play continues to climb and each well drilled requires a frac job. Second, the supply of water needed for these fracs has become scarce. The water access issue is driven by the activity factors mentioned here in addition to the northcentral Texas region being affected by a drought for an extended period.

The National Oceanic & Atmospheric Administration has reported significant rainfall deficits from January 15, 2005, to November 15, 2006, throughout northcentral Texas. Rainfall at Dallas-Fort Worth International Airport alone was 64% of normal. Water-use restrictions are in effect in Dallas and Fort Worth.

Some permitting and municipal ordinance issues arise as operators seek more access to areas increasingly close to Fort Worth and in other outlying areas that are fully developed for commercial and residential use. In general, landowners are driving tougher deals, demanding higher lease bonus amounts, higher royalties and stiffer drilling commitments.

From a competitive standpoint, the play is showing characteristics typical of other areas of E&P activity: larger companies are consolidating acreage, reserves and production from smaller companies. Many of the smaller and often privately owned companies have

EARLY-STAGE PLAY

In Quebec, Canada, Talisman Energy is chasing the Paleozoic-age Utica Shale. Talisman drilled an exploration test looking for the Trenton Black River formation in this area. It proved unsuccessful, but there were good gas shows from the Utica. Testing and a completion are being evaluated.

The company will be drilling more of these Trenton Black River prospects, also testing this uphole shale on the way to total depth. These will be vertical wells.

Micro-cap E&P companies Questerre Energy and Altai Resources are also involved.

SHALE SHAKER

A shale shaker is the primary device on the rig for removing drilled cuttings from the drilling fluid or mud. This vibrating sieve is basically a wire-cloth screen that vibrates while the drilling fluid, together with rock cuttings from the just-drilled formation, flows on top. The liquid phase of the mud and the portion of the cuttings smaller than the wire mesh pass through the screen, while larger pieces of cuttings are retained on the screen and discarded or saved and bagged as samples for the drilling records. The used fluid is then recycled to go downhole again and bring more cuttings to the surface.

The drilling crew seeks to run the screens as finely as possible, without dumping whole mud off the back of the shaker. Where it was once common for drilling rigs to have only one or two shale shakers, modern high-efficiency rigs are often fitted with four or more, giving more area of wire cloth to use and providing the crew with the flexibility to run increasingly fine screens.

Source: Schlumberger Ltd. and Natexis Bleichroeder Inc.

completed one or more rounds of initial and subsequent drilling programs. These positions are now attractive to the larger companies, and the smaller companies see this as a good opportunity to monetize their investment. (See article on mergers and acquisitions elsewhere in this report.)

During the first half of 2006, Devon Energy, Chesapeake Energy, Range Resources and XTO Energy dominated Barnett Shale acquisitions, which have focused on smaller companies or asset packages of smaller companies.

Many in the industry have asked about the future involvement of the major oil companies in what appears on track to become the largest onshore gas field in the U.S. ExxonMobil and Shell are involved on a relatively small basis. ConocoPhillips is in the Barnett, but its position is because of its acquisition of Burlington Resources.

Given their financial strength and technical abilities, the majors are well suited to plays involving large amounts of capital, complex operating characteristics and long lead times. These parameters do not describe the Barnett Shale.

However, given the total resource potential of the play, we would not rule out further expansion by the majors, most likely involving an acquisition. We would envision an acquisition candidate that has large Barnett Shale exposure, plus other, meaningful international and/or U.S. deepwater Gulf of Mexico exposure. Companies in this category, in our view, are Devon Energy and EOG Resources.

Fayetteville Shale

Since our last update, the most noteworthy data point from this play continues to be the slick-water frac completions performance on the horizontal wells. Southwestern Energy Co., which is the dominant operator, discovered the play. Previously, the majority of Southwestern's completions involved nitrogen foam fracs, possibly because of the low pressure of the reservoir. Since the beginning of

Table 2. *Recent wells drilled by Newfield Exploration in the Woodford Shale.*

Production Commenced	Well	Initial Peak Flow Rate (MMcfe per day)	Wellbore Design	Frac job	Post Peak Flow Rate (MMcfe per day)
MOST RECENTLY ANNOUNCED WELLS:					
November 2006	Stuart #1H –13	10.6	2,500' lateral	five-stage	
November	Tollett #1H-22	10	2,500' lateral	five-stage	6
November	Tipton #1H-23	7	3,500' lateral	seven-stage	5
November	Turpin #1H-35	7	1,600' lateral	three-stage	
November	Bullock #1H-15	5	3,500' lateral	five-stage frac	4.1
Mean		**7.9**			**5.0**
Median		**7**			**5**
PREVIOUSLY ANNOUNCED WELLS:					
March 2006	Parker 1H-36	6	NA	NA	4.8
March	Reeder 1H-10	3	NA	NA	2.6
March	Whitlow 1H-27	3	NA	NA	2.4
Mean		**4**			**3.3**
Median		**3**			**2.6**
% improvement		**98%**			**54%**
		133%			**92%**

Table 3. *Economics of Woodford Shale Core Area: $6.00/MMBtu Henry Hub gas price.*

Year	Production MMcfe	Realized Gas Price ($/MMBtu)	Total Revenue	State Production Taxes (5)	Less LOE and other (6) ($MM)	Before Tax Income	Income Taxes	Net Income
1	1059	5.40	5.7	0.09	0.8	4.9	1.7	3.2
2	370	5.40	2.0	0.03	0.3	1.7	0.6	1.1
3	345	5.40	1.9	0.03	0.3	1.6	0.5	1.0
4	320	5.40	1.7	0.03	0.3	1.5	0.5	0.9
5	298	5.40	1.6	0.02	0.2	1.3	0.5	0.9
6	277	5.40	1.5	0.10	0.2	1.2	0.4	0.8
7	258	5.40	1.4	0.10	0.2	1.1	0.4	0.7
8	240	5.40	1.3	0.09	0.2	1.0	0.4	0.7
9	223	5.40	1.2	0.08	0.2	0.9	0.3	0.6
10	207	5.40	1.1	0.08	0.2	0.9	0.3	0.6
11	193	5.40	1.0	0.07	0.2	0.8	0.3	0.5
Cumulative reserves (Bcfe)			3.8					10.9
Cumulative net income								10.9
Completed Well Costs ($MM)								4.0
Net income								6.9
After tax rate of return (assumes average gross reserves of 2.5 - 3 Bcfe per well and 20% royalty)								172%

2006, the company ceased nitrogen fracs and began using slick-water and cross-link gel fracs.

Southwestern reported third-quarter 2006 gross production of 70 MMcf per day in the Fayetteville Shale. It expected to increase production to 100 MMcf per day by year-end 2006, a 43% increase in just one quarter.

In mid-November 2006, Southwestern had 14 rigs working in the play area, up from 10 rigs on July 31, 2006. It planned to have 19 rigs running in the Fayetteville Shale by year-end 2006 and running through 2007. Southwestern expects to have four more company-owned shallow rigs and 15 company-owned deeper rigs by year-end 2007.

Other companies with significant acreage positions in this play are Chesapeake Energy with 340,000 net acres, XTO Energy with about 220,000 acres, Contango Oil & Gas Co. with 44,000 acres, Storm Cat Energy with 13,000 acres, and Carrizo Oil & Gas Inc. with 15,000 acres.

Chesapeake planned to have seven rigs in the region by year-end 2006. Carrizo has a 2% working interest in two wells Southwestern operates. Completions of these two wells were scheduled from November 2006 through February 2007. Carrizo has no plans to drill individually but assumes it will be pooled into drilling more wells with Southwestern in 2007. Carrizo is still acquiring acreage in Pope, Van Buren and Conway counties.

Edge Petroleum, with 6,000 net acres in the Fayetteville Shale, took part in several non-operated wells during third-quarter 2006. Additionally, it expected to drill an Edge-operated well in November. There are future plans for Edge to drill one or two

company-operated wells in 2006 and 2007. The company continues to expand its acreage in the Fayetteville Shale.

XTO is currently a participant in 40 wells, primarily drilled by Southwestern. XTO will begin independently drilling its own Fayetteville Shale wells in 2007.

Contango Oil & Gas is continuing its investment in the play, which is of meaningful size in relation to the company's market cap. Contango is committed to 87 wells with an average working interest of 15%. It plans to drill 10 more wells with an approximate 40% working interest in 2007. Contango was expecting 40 producing wells by year-end 2006.

Penn-Virginia Oil & Gas, with 13,000 net acres, recently spud its first horizontal well, with a 70% working interest. It participated with Southwestern in two other wells. Before the end of 2006, Penn-Virginia expected to drill two additional horizontal wells.

Storm Cat has identified six locations targeted for drilling by the second quarter of 2007. Storm Cat owns or controls 13,000 acres. Currently, the company is preparing for the wells, acquiring permits, pipeline access, and negotiating and securing drilling services. Recently, Storm Cat increased its position and agreed to acquire 340 net acres in Cleburne, Conway and Faulkner counties.

Barnett-Woodford Shale

This play has turned in mixed results to date. So far, some wells in this area, primarily in Reeves and Culberson counties in far West Texas, have been difficult to drill and complete. Sources indicate one recent, unnamed well reportedly came in with a completed well cost of $16 million.

Recent activity includes:

- ***Carrizo Oil & Gas***—Most of this company's acreage is in the Marfa Basin, close to acreage positions of The Exploration Co., Continental Resources and Quicksilver Resources. Carrizo is talking to other companies about a group 3-D seismic shoot and is doing ongoing technical work. In southern Reeves County, the company has participated in several wells with mixed results. Water production has been a problem and this is being analyzed. A portion of the Carrizo acreage is in Eddy County, New Mexico, where there are no immediate plans except to observe industry activity.
- ***EnCana***—This company is in negotiations with numerous industry participants on farming out portions of its 650,000-acre position to speed the evaluation effort.
- ***Quicksilver Resources***—This firm planned to drill a third Barnett-Woodford well before year-end and then complete all three. There has been no mention of results so far.
- ***Southwestern Energy***—The company is continuing completion operations on its first two vertical wells. No results have been released.

Floyd Shale

Operators appear to be doing a good job holding their well information "tight" in the Floyd Shale play.

- ***Murphy Oil, Noble Energy***—We understand these companies drilled five wells as partners and have had two additional wells permitted but not yet drilled. Information is being tightly held. We understand that cores have been or are being analyzed.
- ***Carrizo Oil & Gas*** completed its 3-D seismic survey and is currently processing the data. Carrizo shot its seismic, lined up a rig and hoped to spud a well by year-end 2006.

Devonian Shale

This play has been a traditional target throughout the Appalachian Basin.

- ***Range Resources***—Through November 2006, Range had drilled 11 vertical and three horizontal Devonian Shale wells in Pennsylvania. Four of the vertical wells have been completed and are producing favorably, with estimated reserve potential between 0.6 billion cubic feet and 1 billion cubic feet per well. The fourth vertical well was recently brought on line at a peak rate of 1.2 MMcfe a day, which is higher than the first three wells.
- By year-end 2006, Range anticipated having 10 vertical wells and two horizontal wells on line. The company is working toward a significant expansion of the Devonian development program in 2007. The hope for expansion is up to 60 vertical wells and four horizontal wells. Range holds 314,000 net acres in this play.
- ***Equitable Resources***—EQT has drilled, completed and is testing one well, and another well has been drilled and is awaiting completion. The company expected to have two more wells drilled by year-end 2006. All are horizontal tests on the Kentucky side of the play.

For more information, contact John White, analyst, *john.white@natexisblr.us* (713) 751-1638 ■.

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BIGGER IN THE BARNETT

According to this consultant, production in the Barnett Shale in the Fort Worth Basin is greater than earlier reports indicated.

By Michael E. (Gene) Powell Jr.

Most production reports on the Barnett Shale play in the Fort Worth Basin have relied on the cumulative data of the Newark East (Barnett Shale) Field as reported by the Oil & Gas Division of the Railroad Commission of Texas (RRC), the oil and gas regulatory authority in the state. The Production Data Query System is available at *http://webapps.rrc.state.tx.us*. That cumulative production total, however, only goes back to January 1, 1993, even though production began in June 1982.

The majority of the production has been in the Newark East Field, but the data does not represent the total production of the Barnett Shale throughout the Fort Worth Basin, because the Barnett now has production in 19 counties with wells spotted up to July 1, 2006 (Figure 1).

Early Production

The RRC data begins reporting cumulative field data as of January 1, 1993, whereas the now-Barnett Shale began producing in 1982. It has produced 25.3 billion cubic feet of gas and 44,543 barrels of oil between 1982 and January 1, 1993.

The RRC allowed other Barnett Shale fields to be named until 2002, when it became apparent this shale was a consistent geological formation varying only in thickness and located in more than 20 counties, at which time the state agency stopped naming new fields in the Barnett Shale (Figure 2).

By 2003, some 17 fields had been named in the Barnett Shale in the Fort Worth Basin. Many of these smaller fields are surrounded by wells producing in the Newark East (Barnett Shale) Field; therefore, all 17 fields in the Barnett Shale need to be included back to 1982 to provide a more realistic look at the production.

Pending Production Data

The RRC requires a lease code to be assigned to a gas well, or to the full lease in the case of an oil well, for that production to be reported in its field reporting system. However, there are a significant number of wells producing in Texas whose production is not being reported because of minor input errors by the operators. There has also been an increase in drilling in Texas in the past four years, but a decrease in personnel at the RRC's Oil & Gas Division. This has added to the backlog in the Pending Production File and represents oil and gas output not yet officially reported.

The RRC did begin allowing operator and well searches of the Pending Production File in 2006. This has allowed greater access to that production data, which needs to be added to the other reported data, to ascertain how much the Barnett Shale has actually produced during any given period. It should be noted that some of the wells in the Pending Production File have produced as long as 18 months, so each time a search is made for a specific field and time period, production data will have changed as input errors are corrected and as production moves from pending status to the field reporting file.

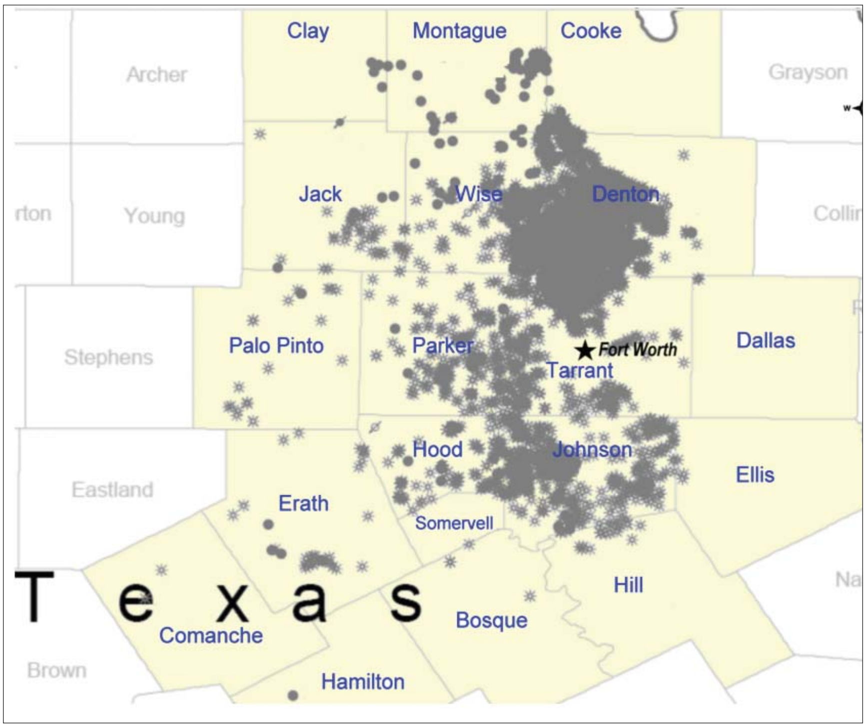


Figure 1. *Barnett Shale producing counties in the Fort Worth Basin, July 2006. Source: IHS Inc.*

Our study of the Pending Production File data from the PI/Dwights database of IHS Inc. for the period studied and ending July 1, 2006, revealed 56.5 billion cubic feet of gas and 153,741 barrels of oil produced from 558 wells. This is "pending" production data that will be added to the final cumulative data.

Our study thus shows total production for the Barnett Shale of the Fort Worth Basin to July 1, 2006, including all fields from 1982—including the pending production not yet reported in field searches—is 2.2 trillion cubic feet of gas and 7.5 million barrels of oil and condensate.

Our research shows 5,926 wells have contributed to the total cumulative production from June 1, 1982, to July 1, 2006. Average daily production for the month of June was 2.07 billion cubic feet of gas and 5,481 barrels of oil and condensate from 5,619 active wells.

The data shows the Barnett Shale Field is now producing 2 billion cubic feet per day, making it the largest-producing gas field in Texas. It is also the second-largest producing gas field in the United States behind the San Juan Basin area of

Table 1. *Barnett Shale Fields in the Fort Worth Basin January 1, 1982 to July 1, 2006.*

Fields	Oil (Barrels)	Casinghead Gas (Thousand cubic feet)	Gas Well Gas (Thousand cubic feet)	Condensate (Barrels)
Newark East 1982 – January 1, 1993			25,306,238	44,543
Newark East January 1992 to June 2006	425,522	6,048,200	2,066,017,365	6,307,042
Cleburne	0	0	6,969,913	2
Saint Jo Ridge	553,827	2,140,491	0	0
Avondale	0	0	1,420,286	26
Jason Dvorin	0	0	247,134	0
Antioch	0	0	1,420,286	26
Rector	0	0	216,154	0
Bowie Northwest	18,226	182,412	0	0
Sanford Dvorin	0	0	159,411	0
Dubois	0	0	88,661	50
Mulliniks	0	0	57,075	0
Denton Creek	4,078	47,343	0	0
Bellevue	6,352	40,777	0	0
Jack County Regular	0	0	28,220	0
Cleburne West (Hancock Shale)	0	0	18,163	0
Wise County Regular	0	0	3,609	296
Lamkin-Hamilton	901	0	0	0
Totals	**1,008,906**	**8,459,223**	**2,100,769,650**	**6,351,959**

Table 2. *Barnett Shale Production in the Fort Worth Basin. All Fields—January 1, 1982 to July 1, 2006.*

Oil (Bbl)	Casinghead (Mcf)	Gas Well Gas (Mcf)	Condensate (Bbl)	Total All Gas (Mcf)	Total Condensate & Oil (Bbl)
1,008,906	8,459,223	2,100,769,650	6,351,959	2,109,228,873	7,360,865
RRC Pending Production File			56,508,728	153,741	
Total Production Barnett Shale				2,165,737,601	7,514,606

New Mexico and Colorado, which includes coalbed-methane gas and tight-gas sands.

Recoverable Gas Assessments

The assessments of recoverable gas resources in the Barnett Shale of the Fort Worth Basin have significantly grown each time a new study is made. We expect another increase when the next analysis is completed, due to the higher well density of horizontal wells (now using 20-acre spacing between laterals), and the greater use of simultaneous fracturing of horizontal wells.

The application of new technology should increase the percentage of recovery of gas-in-place from the current estimate of up to 15%. The first two estimates were from the United States Geological Survey and the last was from Advanced Resources International Inc. in a study of U.S. unconventional gas made for the Energy Information Administration's 2006 Energy Outlook in March:

1996	United States Geological Survey	3 Tcf
2004	United States Geological Survey	26 Tcf
2005	Advanced Resources International Inc.	39 Tcf ■

__Gene Powell__ has spent four decades in the oil and gas industry working in management for a major, a large independent, as an operator with 10 field discoveries to his credit and as a consultant. He has well interests in the Barnett Shale and has sent out the Powell Barnett Shale Newsletter of articles and studies via e-mail weekly at no charge since 2003. He can be contacted at mepowell@barnettshalenews.com

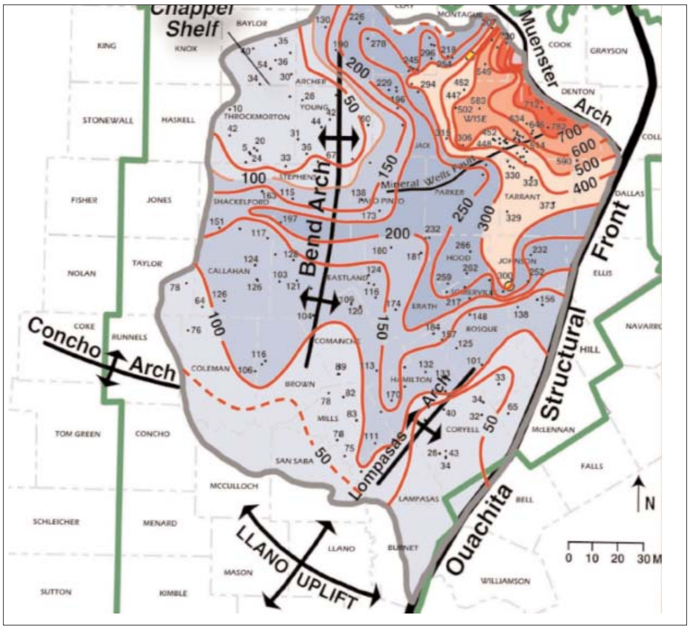


Figure 2. *U.S. Geological Survey Province 50 Boundary, Bend Arch—Fort Worth Basin Regional Isopach Data, Barnett Shale. Source: Rich Pollastro, 2004*

FAYETTEVILLE MATURING

A recent study shows how different the geology and petrophysics of the Fayetteville and Moorefield shales are from the Barnett Shale.

By Kent A. Bowker, George Moretti Jr. and Lee Utley, ShaleQuest Partners

During the past year, Southwestern Energy Co. and other operators (most notably Chesapeake Energy) have further delineated the Fayetteville Shale play in the Arkoma Basin of Arkansas. Southwestern has also reported some excellent results from recent horizontal wells in the play utilizing water fracs. For example, the Southwestern Energy Grills No. 2-31-H made 95.5 million cubic feet of gas in August 2006.

The Fayetteville appears to be maturing past the exploratory phase in the initial fairway or core area of Conway, Faulkner, Van Buren, Cleburne and western White counties, with an average estimated ultimate recovery for the latest horizontal wells in this region appearing to be above 1.5 billion cubic feet. However, there have been disappointing results so far in the eastern extension of the play into the Mississippi Embayment, such as Lee, Woodruff, St Francis and eastern White counties.

As of November 2006, according to state records, there were 123 producing Fayetteville/Moorefield (more on the Moorefield later) wells in the core area of the play in Cleburne, Conway, Faulkner, Van Buren and western White counties. Southwestern (114), Chesapeake (8) and Yale Oil (1) operated the respective wells.

In addition, there were more than 250 active drilling permits (wells currently drilling, being completed, being tested or staked) for these counties.

In addition to Southwestern and Chesapeake, which are the most active players, companies with outstanding permits include Hallwood Petroleum, Maverick, Pathfinder, CDX Gas, Aspect Energy, Teepee (also known as Alta Resources, which has the partial financial backing of George Mitchell of Mitchell Energy & Development), J-W Operating, Edge Petroleum and David Arrington. Shell Oil Co. has a large leasehold in the play but has elected, at least to this point, not to operate any of the wells in which it has a working interest.

In 2006, Chesapeake announced that about 700,000 of its 1 million acres were not currently prospective based on its disappointing drilling results in the Mississippi Embayment-portion of the play. However, various companies have applied for more than 20 drilling permits in Woodruff, St. Francis, Monroe, Phillips, Jackson, Lee and Prairie counties, all in the eastern (Mississippi Embayment) portion of the play.

Geology

There is a general lack of industry knowledge about the potential shale reservoirs in the Arkansas portion of the Arkoma Basin. Using our experience in the Barnett and other shale plays, we have completed an extensive geologic and petrophysical study of the Fayetteville Shale. It soon became clear that the Moorefield, which we divided into a lower and upper unit, was also a prospective horizon.

Since we began our work, Southwestern Energy has completed at least one well in the Upper Moorefield in Cleburne County. The Woodford Shale, now prevalent in southeastern Oklahoma, has also been tested in the basin, but we don't believe there is sufficient gas-in-place to warrant a complete study at this time.

We correlated logs from all available wells (about 150) in the eastern portion of the Arkansas part of the Arkoma Basin and Mississippi Embayment. We also constructed nine regional cross-sections across the basin, and constructed 21 maps to help understand the geology of the Fayetteville and Moorefield shales.

In many ways, the stratigraphy and structural geology of the Arkoma Basin are more complicated than in the Fort Worth Basin, making the exploration and exploitation of the Fayetteville and Moorefield shales more difficult than the Barnett.

One problem or misunderstanding is where exactly in the stratigraphic column the Fayetteville lies. In short, we agree with the stratigraphy data used by Southwestern Energy, and think that the formational boundaries used by the Arkansas Geological Commission, though possibly technically correct in a biostratigraphic sense, are not useful for geologists prospecting in the basin.

A quick examination of wireline logs across the relevant stratigraphic section shows that the higher gamma ray-higher resistivity shales are the prospective intervals, not the shale higher in the stratigraphic column (between the Fayetteville and the overlying Hale).

The Ouachita Thrust Belt is a common factor in natural gas production in these plays:

- Barnett Shale in the Fort Worth Basin;
- Woodford and Caney shales on the Oklahoma side of the Arkoma Basin;
- Fayetteville, Moorefield and Chattanooga shales on the Arkansas side of the Arkoma; and
- Floyd/Neil shale in the Black Warrior Basin of Mississippi and Alabama. (See related article elsewhere in this report).

Without the emplacement of the Ouachitas and the resultant heating events across these basins, there would be no gas production from these reservoirs. The continental-scale thrusting events acted like a series of squeegees, pushing hot, mineral-laden brines out in front of the thrust sheets.

This brine moved through the underlying Ordovician strata (e.g., the Ellenburger in the Fort Worth Basin) and heated the shallower rocks (Mississippian and Devonian shales) to a point much hotter than would be expected with a "normal" Midcontinent burial history. Without this additional heat flow, many portions of these basins would not have made it into the gas window.

The highest heat flow was in the Arkoma Basin, probably because of its location at the apex of the Ouachita Trend. The lead-zinc deposits of the Tri-State mineral district of the southern Ozarks were emplaced as a result of this hot-brine migration.

Fayetteville Shale

It quickly becomes obvious that the Fayetteville Shale is different from the Barnett of North Texas. Most importantly, the Fayetteville was deposited in a much different environment than the Barnett; and, hence, it's restricted to a smaller area. There were abrupt facies changes during the time the Fayetteville was deposited, especially to the east toward the Embayment and south toward the Ouachita Thrust Belt, that create hazards for exploration for gas in this formation.

The thickest portion of the Fayetteville Shale is toward the north and northwest, at the outcrop belt. This is in direct contrast to the Barnett, where the thickest section is in the deepest portion of the Fort Worth Basin, which is in front of the Muenster Arch in Montague County. This "upside down" thickness pattern, such that the thickest shale interval is toward the basin margin, gives some indication as to the depositional system responsible for the Fayetteville Shale.

The Moorefield Shale lies just below the Fayetteville; a relatively thin limestone unit called the Hindsville separates them. We divided the Moorefield into a lower and upper unit, with the upper being the more perspective unit.

Petrophysical Traits

Historically, critical petrophysical parameters have been difficult to predict in gas shales. Techniques developed through years of experience in the Barnett Shale in the Fort Worth Basin were used here to tie the limited core data to the more widely available log data. Models were developed to predict porosity, water saturation and gas-in-place (free and sorbed) in the Fayetteville, and upper and lower portions of the Moorefield shales. We have mapped these.

For the Fayetteville Shale study, we began by digitizing the pertinent log data for more than 120 wells. Preliminary formation correlations were made to aid in analysis. The models require gamma ray, bulk density and resistivity logs. The gamma ray and bulk density data were normalized to account for calibration issues. We patched the bulk density data to eliminate false reading because of washouts. Resistivity inversion analysis, performed on old E-log data, old induction data and dual-laterolog data, eliminated discrepancies because of different generations of resistivity tools. The cleaned and normalized log data enabled more confident stratigraphic correlations.

Modeling of petrophysical parameters is based on available core and cuttings data, including standard gas shale core data for two wells, the Thomas 1-9 and the Thomas 1-16 (both drilled by Southwestern Energy) and geochem analysis from cuttings on 45 wells.

We trained and confirmed neural network models to calculate porosity and total organic carbon (TOC) using the core data. The TOC model was further confirmed using the cuttings-derived geochem data. We developed deterministic models to calculate water saturation and gas-in-place, comparing these results to published core data. ■

THE FLOYD/NEIL SHALE

In the Black Warrior Basin of Alabama and Mississippi, operators are trying to develop the potential of a new shale play.

By Kent A. Bowker, Bowker Petroleum LLC

During the past year and a half, there has been a slow, but continuous, industry effort to explore for and develop the gas resources of the Floyd Shale in the Black Warrior Basin. The black-shale interval of the Floyd, which is the Alabama name for the formation, is called the Neil Shale in Mississippi, but they are the same prospective shale interval.

Recently a high-profile deal drew more attention to the play, when Chesapeake Energy Corp. entered Alabama by forming a 50-50 area of mutual interest (AMI) with Alabama expert Energen Resources, the E&P arm of the local utility. Chesapeake announced a $90-million deal with Energen that involves the latter company's position in the Floyd Shale play. Chesapeake will earn a 50% interest in Energen's 200,000-net-acre position in the Alabama portion of Black Warrior and Appalachian basins. They said the AMI they have formed will focus for the next 10 years on new leases and operations in the area.

In light of this deal, Chesapeake now says it has accumulated 4.25 million net acres of prospective shale leases "in every major shale play east of the Rockies."

Geology

The Floyd Shale is the stratigraphic equivalent of the Fayetteville and Barnett shales, but in its depositional history, it is more akin to the Fayetteville of Arkansas. In a fashion similar to the Fayetteville, the organic-rich black shale facies of the Floyd appears to grade laterally into leaner, and probably non-prospective, shale facies in various portions of the basin.

The organic-rich portion of the Floyd ranges up to about 150 feet thick and is about 4,000 to 10,000 feet deep across the play. Understanding the distribution of the organic-rich facies within the Floyd will be a key factor —along with the structural geology, well design and well-completion design—in the eventual success of the play.

There do not appear to be any karst features (sinkholes) present in the Black Warrior Basin. These are common in the Fort Worth Basin, however, and are considered a hazard to be avoided in the Barnett Shale play under way there. To detect karst features and faults, operators conduct 3-D seismic surveys in this play. Faults are present in the Black Warrior Basin, but they don't appear to be so abundant as to cause more than a slight distraction in the development of the Floyd Shale play once they are mapped accurately.

Activity Begins

Activity in the play began in mid-2005 with vertical wells drilled by Denbury Resources (a long-time North Texas Barnett veteran) in Mississippi and Murphy Oil Co. in Pickens County, Alabama. Denbury has recently completed a horizontal well in southern Lamar County, Alabama. Elysium Energy (now acquired by Noble Energy), Cabot Oil & Gas, Anadarko Petroleum, Wagner and Brown, and David Arrington have drilled wells in the Floyd Shale.

Privately held Arrington's effort has been the most aggressive to date with a vertical frac-mapping well. According to reports from the field, the Floyd Shale was cored in this well, a vertical pilot well, and an offsetting horizontal well was being drilled at press time. These wells are in northern Lowndes County, Mississippi. Arrington is apparently the largest lease holder in the play: aside from leasing for its own account, Arrington acquired Noble's position in north Pickens and Lamar counties, and made another large purchase of acreage in Alabama and Mississippi.

Murphy Oil's acreage position appears to be across a large portion of the basin, based on the location of wells it has permitted. No production has been reported from the five vertical wells Murphy has drilled in Pickens County, though three of them are reported as currently testing following perforating and fracing.

In a fashion similar to the Fayetteville, the organic-rich black shale facies of the Floyd appears to grade laterally into leaner, and probably non-prospective, shale facies in various portions of the basin.

In mid-November 2006, Murphy announced a major reorganization of its E&P management, moving all worldwide E&P activities under one group based in Houston. It will be interesting to see if this impacts the firm's Floyd Shale efforts.

Anadarko recently drilled a pilot well in Clay County, Mississippi, with a possible horizontal kick-out to follow from this wellbore.

Anadarko recently finished drilling a pilot well in Clay County, Mississippi, with a possible horizontal kick-out to follow from this same wellbore. The company plans to drill additional wells in this portion of the Floyd Shale play, its only company-operated effort in a domestic shale play in many years. (It also holds acreage in the periphery of the Texas Barnett Shale play thanks to its recent acquisition of Western Gas Resources.)

Also active in the play with acreage positions are Edge Petroleum, Bankers Petroleum, Lario Oil & Gas, Carrizo Oil & Gas and Marlin Energy.

Because activity is new, few details are available, but operators continue to lease. ■

Kent Bowker *is a principal with ShaleQuest Partners LLC and Bowker Petroleum LLC. This is excerpted from a new study the firm has done on the Floyd Shale.*

UNDERSTANDING THE BARNETT SHALE

Now that nearly 6,000 wells have been drilled, the industry has better knowledge of what makes the Barnett Shale tick.

By Randy LaFollette and Gary Schein, BJ Services

The Barnett Shale of the Fort Worth Basin has been recognized for some time as a major unconventional gas resource play, that is, a continuous accumulation requiring advanced technology for production. Since the Mitchell CW Slay No. 1 well was drilled and completed in 1981, the Barnett play has seen significant changes in understanding the reservoir, technologies applied and success.

What are some of the lessons learned from the standpoint of a service company actively fracturing Barnett wells?

Understanding the Reservoir

Shales are sedimentary rocks defined by their particle size range. Just as sandstone is defined as a clastic sedimentary rock having most of its grains about the size of sand, shale has most of its particles about the size of clay. True shales exhibit the property of "fissility," splitting along closely spaced horizontal planes of weakness as a result of alignment of platy minerals, the micas. A clastic sedimentary rock fitting the particle-size range of shale, but lacking the property of fissility, is termed a mudstone or claystone.

None of these rocks is defined by their mineralogy, and they can all have variable mineral contents, which affect reservoir quality in the fractured shales by the presence of higher percentages of the more brittle minerals, especially quartz. Such rocks have potentially more natural fractures than rock with higher clay or carbonate mineral content. Variability in shale particle-size ranges may affect matrix permeability, which is low in the extreme.

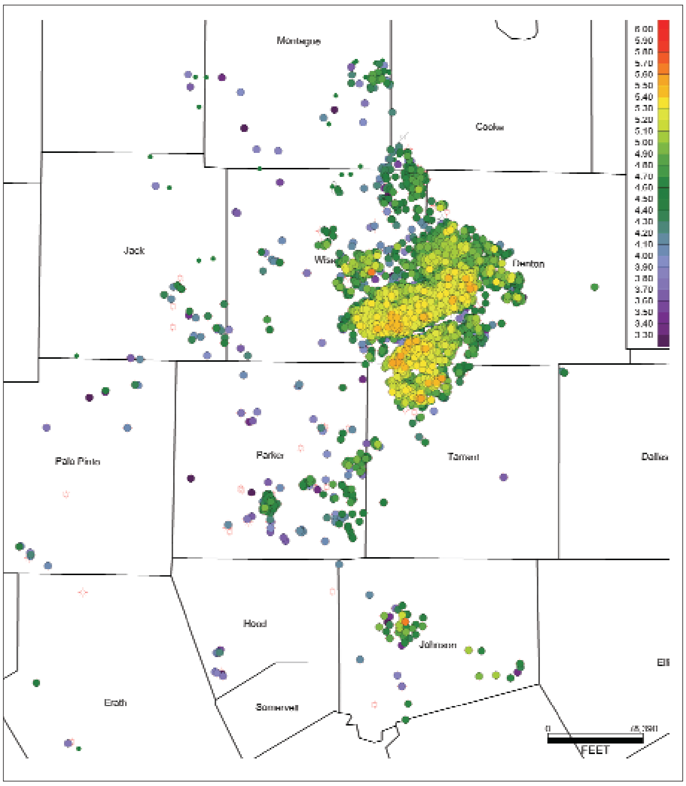


Figure 1. *The best Barnett Shale vertical gas wells are shown in orange or red, the lowest producers are in purple.*

Matrix permeability numbers commonly referenced in Barnett Shale discussions range between 10-7 and 10-9 Darcies. Interbeds or laminations of silt- and sand-sized particles may radically improve local matrix permeability. Open, or partly open, natural fractures, where present, improve system permeability.

There is a vast difference between "continuous accumulation" and "constant" or even "constantly and predictably varying" reservoir properties. While the Barnett is a continuous accumulation, critical reservoir properties are far from constant, both vertically and laterally.

In the fractured gas shale and tight sandstone worlds, gas-in-place (GIP) numbers receive a lot of attention and tend to be extremely large numbers that get people excited. GIP is fundamentally driven by porosity, thickness, drainage area, gas saturation and reservoir pressure. While GIP numbers are difficult to quantify, only a small fraction, about 10% to 20% of the gas in the Barnett, is recoverable with present technology and techniques.

Deliverability, or gas rate, is driven by five "reservoir-only" parameters: permeability, thickness, reservoir pressure, reservoir fluid viscosity and drainage radius. Additional driving parameters are wellbore flowing pressure, wellbore radius and skinparameters that can be affected by drilling, completion and stimulation practices.

The Barnett is a variably productive reservoir. Figure 1 bubble-maps sweet and not-so-sweet Barnett producing areas. The map shows vertical Barnett wells having at least seven months of public production data in the IHS database and readily delineates the original Barnett core producing area. Based on the public data as of October, the sweet spots in which the best 10% of vertical wells have been drilled have been restricted to specific areas within Denton, Wise, Tarrant and Johnson counties. Changing the map to show the best and worst 10% of those wells highlights their geographic separation and strongly implies variation in critical reservoir properties.

One of those key critical reservoir properties is hydrocarbon liquids. Figure 2 shows normalized six-month Barnett oil cumulative production. Oil production increases to the northwest, and the core area gas-producing sweet spots occur where oil production is least. A map of Barnett water-to-gas ratio shows a similar trend, indicating that produced liquids are not good when combined with gas production in very low-permeability rocks.

Other factors also drive the locations of these sweet spots to include degree of natural fracturing, faults, Ellenberger karsting (dissolution features) and the Viola Limestone fracture barrier. Figure 3 shows the vast majority of the best vertical wells were

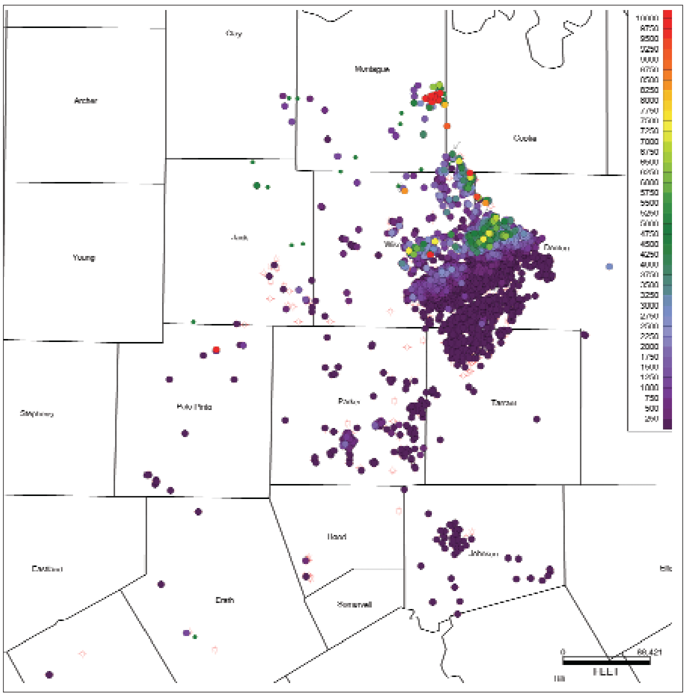


Figure 2. *Normalized six-month cumulative oil production shows low oil output in the core sweet spots for gas.*

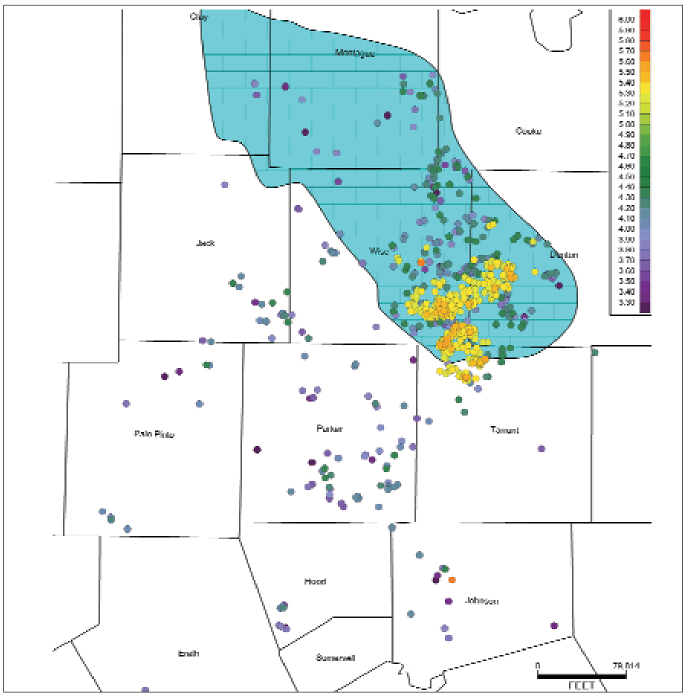


Figure 3. *Best 10% and worst 10% of vertical gas producers are compared to the Viola Limestone (turquoise) that underlies the Barnett Shale.*

drilled in areas where the Viola Limestone underlies the Barnett, resulting in a hydraulic fracturing barrier between the Barnett and wet Ellenberger. The Barnett is not a simple formation with a set of constant reservoir properties, and this is combined with varying geomechanical hurdles to overcome. This implies technology needs may vary as well.

Technologies

Two of the major advanced technologies critical to expanding Barnett success have been horizontal drilling and slick-water fracturing. Ultra-lightweight proppants may also play a role, particularly as new, higher strength versions come out of the research laboratories and into the field. Simultaneous fracturing of offset horizontals is another newer technology showing promise in the Barnett.

Figure 4 is a timeline of Barnett vertical and horizontal well normalized six-month cumulative gas production. White data points represent vertical wells, and blue data points represent horizontal wells. Note that horizontal drilling in the Barnett was tried one time in 1992. Production at the time was worse than that of most vertical wells, so horizontal driling was not attempted again until 1998. Six to 10 more horizontal Barnett completions would be required before production was considered acceptable and horizontal technology begain to be deployed widely in the Barnett. The lesson seems clear: a single poor result early on delayed by several years what was later proven to be a sound technology.

Horizontal drilling—After its somewhat rocky start, horizontal drilling became a game-changing technology in the Barnett in 2003. Figure 4 also shows the best vertical wells produce about 350,000 Mcf of gas during the first full six months of production. This compares with the best horizontal wells producing nearly 1 billion cubic feet during the same normalized time period.

Producing more gas from fewer wellbores was important, but horizontal drilling had another even more important contribution to make: it permitted successful Barnett wells to be drilled in areas where vertical wells were poorly performing. Horizontal wells that produced as well as or better than the best core area vertical wells could now be drilled well away from the core area, generating successes in southern Tarrant and Johnson counties.

Horizontal well length and azimuth have been correlated to Barnett gas production in specific areas. Based on the publicly available production data, optimum horizontal well lengths are between 3,000 and 4,000 feet, including the build section.

Early production data largely from the core area and from Johnson County indicated optimum well azimuth was between 120° and 140° or 300° and 320° in those areas. This relationship is not apparent for all Barnett producing areas. Drilling along 120° to 140° or 300° to 320° approximately parallels the main natural fracture sets and allows placement of transverse hydraulic fractures, creating maximum surface area for gas production from very low permeability matrix into an interconnected network of natural and induced fractures and then to the wellbore.

It is important to recognize that simply drilling and completing horizontal wells in the Barnett does not guarantee success. Many horizontal Barnett wells have been drilled in areas of poor reservoir quality or have had drilling, completion or other operational problems resulting in poor production rates.

Fracturing—Slick-water fracturing was first applied to the Barnett between 1997 and 1998 and slick water soon became the Barnett fracturing fluid of choice. Slick water is a much simpler fracturing fluid than the cross-linked gels. Where these gels are complex mixtures of water, polymer, cross-linker and buffer, slick water is made up of water and friction reducer. Both fluid types may also contain additives such as biocide, surfactants and scale inhibitors, depending on specific treatment requirements and goals.

The changeover from large cross-linked gel fractures saved Barnett operators an estimated 30% of frac cost without sacrificing production.

Typical vertical well frac designs are based on between 2,200 and 2,400 gallons of fluid per foot of gross height. The pad comprises between 30% and 40% of total fluid, with 50% of the slurry using proppant concentrations between 0.1 and 0.65 pounds per gallon with the final 10% of the slurry ramped up to 2 pounds per gallon. Current practice calls for Ottawa sand in 40/70 mesh and 20/40 mesh size ranges, with some operators in some areas pumping mainly 100-mesh sand and tailing in with 40/70. Jobs are pumped at injection rates between 40 and 85 bpm.

Vertical wells in areas where the Barnett is thin or the lower Viola frac barrier is questionable or absent will be pumped at rates on the low end of the range. Barnett fractures targeting thicker zones have the option of being pumped at higher rates.

Typical horizontal well fracture designs call for multi-stage, 0.8- to 1.5 million gallon treatments of slick water per stage with between 10% and 12% pad, 75% and 80% proppant in the 0.1 to 0.65 pound per gallon concentration range, and the final 10% ramped up to 2 pounds per gallon. Some Johnson County wells have been fractured with as much as between 7- and 8 million gallon jobs. Horizontal wells are commonly fractured down casing at injection rates between 70 and 100 bpm range for 5½-inch pipe and 150 to 200 bpm for 7-inch pipe.

The goals of hydraulically fracturing the Barnett are to create a maximum amount of conductive surface area deep in the reservoir and provide a series of relatively high conductivity flow paths to the wellbore. There are four ways to transport proppant deep into the reservoir: increasing injection rate, increasing viscosity of the fracturing fluid, decreasing proppant mesh size and decreasing proppant specific gravity.

Increasing injection rate can be useful, but may not be desirable in areas where the frac may tend to grow downward into the wet Ellenberger. Increasing viscosity by using cross-linked gels will carry more proppant and transport it further than slick water. However, cross-linked gelled water may also yield a less complex hydraulic fracture with less surface area for gas production and costs significantly more than slick water. Decreasing proppant mesh size has been a trend for some time and seems to provide some benefits. Smaller diameter proppant particles will enter narrower fractures than coarser materials and require less forward velocity to keep them moving.

The lower specific gravities of ultra-lightweight proppants, such as BJ LiteProp materials, also appear useful in certain Barnett applications. The story of ultra-lightweight proppants is not yet fully written as early generations of these materials did not have the crush resistance necessary for application across much of the Barnett. Newer generations of the LiteProp family of proppants may see widespread use in the future.

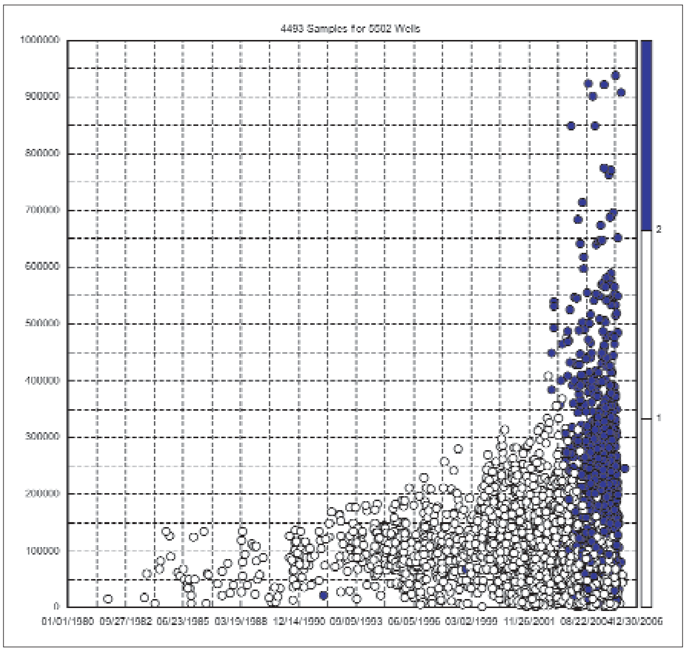


Figure 4. *In this production timeline, the blue dots are horizontal wells, a game-changer that greatly increased Barnett gas production.*

Simo-Fracs

The most recent trend in Barnett fracturing is the simultaneous fracturing (simo-fracs) of paired offset wells. The theory behind simo-fracs is to minimize intrusion of frac fluid and proppant from either well into the other as a result of high-induced stresses caused by frac slurry injection. The method is too new to be able to say with certainty that it results in a long-term production improvement over fracturing each well separately and at different times. However, where the production data exists and can be compared with non-simo-frac offsets, the method appears to have promise.

In one comparison of normalized six-month cumulative gas production in central Tarrant County, the simo-frac wells are producing significantly more gas per foot of lateral than the offsets that were not simo-frac'd. Other simo-frac'd wells are showing higher production than their offsets in the short term. Time will tell whether simo-fracturing is a game-changing technology in the Barnett, but initial results point to a potentially promising technology. ■

Randy LaFollette *is BJ Services manager, applied geoscience, working from the research and engineering campus in Tomball, Texas. He is a geologist with 29 years experience in the industry and has worked in field, region and research level positions.*

Gary Schein *received a bachelor's of science degree from Northern Arizona University in 1978 and has worked in well completions and stimulation for more than 28 years. He has also worked in research and development, technical support, marketing and field engineering positions.*

DECISION-MAKING FOR UNCONVENTIONAL RESOURCES

Understanding value and risk leads to better decisions, but in unconventional plays, the process must be handled differently.

By P. Jeffrey Brown, William J. Haskett and Patrick Leach, Decision Strategies Inc.

Unconventional resource plays are one of the hottest topics in the oil and gas industry today. Potentially lucrative economic engines, these plays were often considered drilling hazards in the past. Today, the combination of high product prices and improvements in completion technology has thrust these unlikely but strategic accumulations to the forefront of domestic exploration and exploitation.

However, evaluating investment decisions associated with these unconventional opportunities requires a radically different approach from that used for traditional plays.

There is no universal definition of an unconventional resource play. In this article, resources such as tight gas, gas- and oil shale as well as coalbed methane are included under the umbrella of unconventional resources. The following chart summarizes differences between play types and how they are analyzed.

Conventional	Unconventional
1. Hydrocarbons are housed in discrete accumulations. For a variety of reasons, the majority of the available containers will prove to be totally dry. (Global commercial success rate has remained remarkably consistent at about 25% since the 1960s).	Hydrocarbons are ubiquitous. A high percentage of locations will find flowable gas. The assessment of geologic chance is much less important for unconventional plays, having a significantly lower impact upon variations in predicted results.
2. The basic units of natural measure for volumetric analysis for traditional targets are individual prospect volumes, or, at the play level, the characteristics of field estimated ultimate recovery for known (or future) discoveries.	Productive boundaries extend beyond the limits of individual company acreage holdings. A cell is the basic, repeatable unit of the play, reflecting the expectation for what each well or well set will recover during its life—its estimated ultimate recovery. Production and cash flow can be modeled for each location and aggregated as part of the simulation of an exploitation program.
3. The key driver in economic analysis is generally uncertainty in success case volumes.	The uncertainties multiply: initial production and decline rates, mechanical efficiency, costs, acreage capture, strategy (and acreage costs) and the timing of the success program can dominate the analysis.
4. When a prospect is tested, the decision to proceed (or not) usually hinges on the results of the initial test well. The decision to proceed in a play, such as whether to continue exploring, occurs after an initial test program for a few prospects.	The key development decision depends on test pilot program results and how representative the pilot results are of the future development.

Decision Points

The operator of an unconventional play should be mindful of downside risk throughout the life of the program. As such, there are three principle decision points for the early exit (off ramp) of the project (Figure 1). In chronological order they are:

Off Ramp 1: Play or Exploration Risk—If the initial well drilled into an unconventional play shows a geologic or technical failure that all other locations are likely to share, then there is no logical reason to drill further locations; the play should be abandoned. Often, a small number of failures must be drilled before a shared risk element is identified as the cause of the failure. Additionally, it may be determined through initial drilling that the productive horizon is unreachable with current technology to the extent needed to achieve a viable chance of production.

Off Ramp 2: Pilot Failure—Unconventional ventures almost always require the execution of one or more pilot programs to provide initial rate and producibility data. Such pilots supply notoriously imperfect information. The convergence of pilot results to eventual program results depends on a number of elements, including the number of pilot wells drilled and tested.

Most of the learning in a pilot is achieved within the first few wells. The objective is to drill the minimum number of wells needed to provide a reasonably correct assessment of the entire program. Beyond this number, the incremental learning per well is insufficient to justify the incremental cost.

When we create a probabilistic assessment for an exploitation program, we can designate a threshold average recovery per well for the test pilot. A full project cash flow is then simulated based on success-case activity levels, and the result of each iteration is checked in hindsight. Each iteration will have one of four possible, discrete outcomes.

A pilot program is successful if it delivers correct information, whether positive or negative. The ability of the pilot program to provide a correct prediction of the profitability of the program is called pilot effectiveness. It is the sum of true positive and true negative probabilities.

Pilot Effectiveness

Pilot program results are tracked based on different pilot sizes (from one to 20 wells). After a large number of simulated passes through the program, a stable picture of the predictive capacity of different pilot sizes is achieved. An example of results is shown in Figure 2. Often, the optimal number of wells shows as an inflection point on the plot of

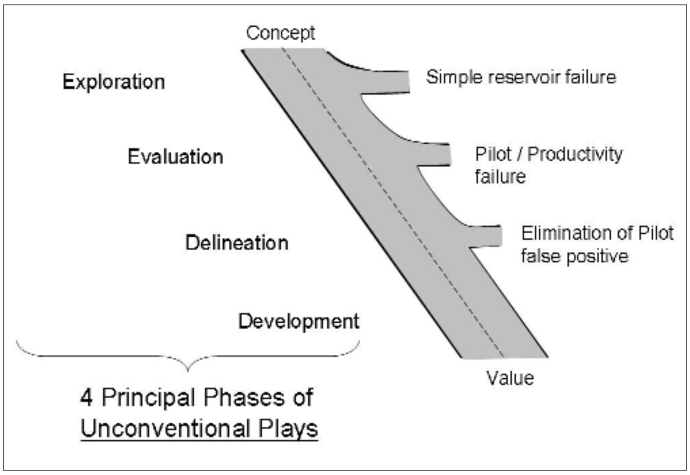


Figure 1. *The four stages of unconventional projects with three early exit points for downside risk mitigation.*

pilot effectiveness versus number of pilot wells. The ability to optimize pilot size may save millions of dollars in well expense on a single project.

The pilot decision can be tested against other criteria, for instance, the average initial potential of wells in test program, but we have found that estimated ultimate recovery (EUR) per well provides the most robust predictions.

Off Ramp 3: Mid-point Program Test—At a certain point in the program, it is important to stop and assess its projected economic benefit. Empirically, this seems to be when 20% to 30% of the intended development program has been completed, given a positive pilot response. Exiting at this point eliminates the significant loss that could result from continuing with a development program that is economically unprofitable.

Fully probabilistic cost assessments are necessary to provide a sound basis for the critical decisions and acreage strategy for the unconventional opportunity. Once a template is established, it is easy to run sensitivities or model different levels of fiscal exposure to see the impact of variable inputs. This sort of testing allows time, people and capital to be allocated to the appropriate activities to maximize the potential for success.

Interpreting Results

Several runs of the stochastic project simulation are usually required to get a good picture of the unconventional project at hand, as well as the options available to the E&P company. The first run of the assessment model should be unconstrained, using no minimum pilot size or minimum mid-point criteria (Figure 3). This provides an "NPV Swarm," (net present value), which is a cross-plot of project NPV versus expected average EUR per well, which is used to determine an appropriate pilot minimum-success test criterion.

In Figure 3, each symbol represents one full-cycle cash flow analysis of an exploitation program (one iteration of the model), where full-project NPV is plotted against the average EUR for all wells modeled on that iteration.

All outcomes in which the average recovery per well is less than 1.7 billion cubic feet per well result in a loss, and all outcomes greater than about 2.4 billion cubic feet per well result in a profit. Outcomes between these end-members are in the zone of uncertainty, in which the investment can result in a profit or a loss.

The assessment should be rerun, testing against a pilot threshold (perhaps 2 billion cubic feet per well in this example), to determine how often the pilot will lead the company down the correct decision path.

After a significant number of wells has been drilled, a "mid-program test" may be applied. If the wells drilled to date have not, on average, met the minimum threshold, the program is stopped. The mid-program test eliminates the downside outcomes from inaccurate pilot results. This is the "elimination of pilot false positive" exit point shown previously in Figure 1.

Figure 4 shows an input scenario identical to that in Figure 3, but to which a pilot and mid-program "hard stop" have been added to the analysis, showing the impact of disciplined decision-making upon the expected profitability of the play. Note the cluster of outcomes located just below the $0 NPV line, representing iterations where the program was stopped because of disappointing pilot (or mid-program) results resulting in abandonment of the venture.

While this decision leads to abandonment of some outcomes, which might have proved profitable, it protects against (and eliminates) most of the spectacular fiscal failures. This results in a significant increase in full project expected value.

Pilot Effectiveness

	Pilot Good Proj. Good	Pilot Good Proj. Bad	Pilot Bad Proj. Good	Pilot Bad Proj. Bad	Pilot Effective
1 well	61%	6%	31%	3%	64%
2 wells	71%	6%	21%	2%	73%
3 wells	76%	6%	16%	2%	78%
4 wells	77%	6%	14%	3%	80%
5 wells	81%	7%	11%	2%	82%
6 wells	83%	7%	8%	2%	85%
7 wells	86%	7%	5%	1%	87%
8 wells	87%	8%	4%	1%	88%
9 wells	87%	8%	4%	1%	88%
10 wells	89%	8%	2%	1%	90%
11 wells	90%	8%	2%	1%	90%
12 wells	91%	8%	2%	0%	91%
13 wells	89%	8%	2%	0%	90%
14 wells	91%	8%	1%	0%	91%
15 wells	91%	8%	0%	0%	92%
16 wells	91%	8%	0%	0%	91%
17 wells	91%	8%	0%	0%	92%
18 wells	91%	8%	1%	0%	91%
19 wells	91%	8%	1%	0%	91%
20 wells	91%	9%	1%	0%	91%

% outcomes that are full-cycle positive: 91%

'True Positives'

'True Negatives'

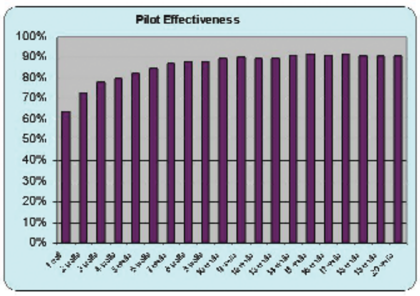


Figure 2. *Pilot Effectiveness Plot.*

Other Outputs

Standard output metrics for unconventional plays are similar to those from conventional opportunities, such as the full probabilistic range for success case aggregate costs, volumes and value, and project efficiency. An integrated evaluation method captures the full range of uncertainty, not only for volumes but also for cost, time and rate inputs, and project-specific outputs can be extracted from the results.

Aggregated production profile results can provide a true probabilistic basis for facility and/or other infrastructure utilization.

A fully probabilistic approach provides management with more useful information than does a deterministic analysis.

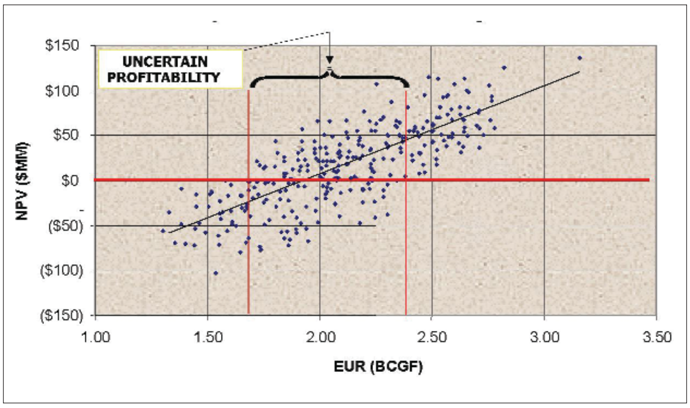


Figure 3. *Cross-plot of full project net present value versus the average estimated ultimate recovery (EUR) per well.*

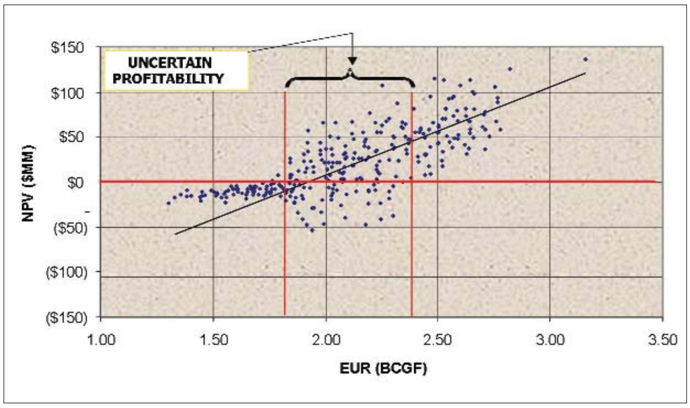


Figure 4. *Cross-plot of full project net present value versus average estimated ultimate recovery per well with pilot and mid-program thresholds.*

Conclusion

Unconventional resources offer a set of challenges not usually encountered with more traditional opportunities. Unlike standard prospect and play risk analysis, geologic chance is not a major issue. Estimates of initial production, decline rates, mechanical efficiency and success planning dominate the analysis, rather than volumetric determinations.

A fully stochastic business value chain context is the best way to assess the full spectrum of potential economic outcomes of an unconventional play. This not only provides a valid approach for value assessment, but also illuminates risk and offers mitigation possibilities. Such an evaluation provides management with the information and strategic insights needed to make good investment decisions. ■

***Jeff Brown, Bill Haskett** and **Pat Leach** are with Decision Strategies Inc. Collectively, they have 80 years of oil and gas experience, each beginning his career with a major oil firm before moving to the consulting field. Decision Strategies Inc. is a leading provider of strategic advice to the oil and gas, chemical and transportation industries.*

FIRST-MOVER ADVANTAGE

When it comes to shale M&A, it's usually the first-movers that hold all the cards.

By Taryn Maxwell, Editor, A&D Watch

As extraction technology continues to improve, areas of the U.S. that were once thought to contain resources that would never see the light of day are now considered some of the most prolific and popular plays. One such play is the shale.

In the 1980s, when George Mitchell, founder of Mitchell Energy & Development Corp., began to work in the Barnett Shale near Fort Worth, Texas, shale gas was but a glint in his eye. Today, companies are clamoring to get a piece of the Barnett, but it is Mitchell's legacy, now a part of Devon Energy Corp., that continues to hold the largest amount of acreage in the play.

"As the shale plays have some success, the deals get pricier," says Brad Foster, vice president and general manager of Devon Energy's central division. "That's where you do very well as a first-mover. If you can be one of the first guys to have the vision and the recognition to get into a play before the acreage costs and the royalty costs go up, you can put a nice acreage position together and make things happen. Devon had the first-mover position in the Barnett. We recognized early on that shale plays would have a long-term impact on the U.S. gas market."

First-mover advantage is so important in the shale plays because once these plays become economical and more valuable, those who hold the acreage are unlikely to sell it. Shale acreage doesn't change hands often, but when it does, the cost can be substantial.

Such was the case on June 29, 2006, when Devon completed its purchase of Chief Holdings LLC for some $2.2 billion, further cementing its top position in the Barnett Shale. The company's properties added estimated proved reserves of 617 billion cubic feet of gas equivalent and some 169,000 acres to Devon's leasehold in the Barnett.

"Chief had a lot of acreage that was undeveloped," says Foster. "We had been very successful in going in and developing our acreage position in the Barnett Shale over the last three or four years, and we feel comfortable that there is still tremendous upside in the play."

Another heavy-hitter in the Barnett Shale is Chesapeake Energy Corp., which also has holdings in all of the major shale plays east of the Rocky Mountains, including the Woodford Shale, the Fayetteville Shale, the New Albany Shale, and various shale plays in Appalachia and Alabama, says Tom Price, senior vice president of corporate development. Despite using its shale knowledge all over the U.S., the company continues to focus on the Barnett.

"We focused on the Barnett due to the relative consistency of the formation, the repeatability of drilling success, the attractive finding and development costs, and the company's land expertise which allows Chesapeake to tackle formidable land problems that most other companies would be intimidated by," Price says.

Chesapeake was very active in shale M&A in 2006, closing some $1.65 billion in deals in the Barnett Shale, including an agreement to lease 18,000 net acres underlying the Dallas-Fort Worth International Airport, the purchase of 1.5 trillion cubic feet of gas equivalent of proved and unproved reserves from Four Sevens Oil Co. Ltd. and Sinclair Oil Corp., and the purchase of acreage from seven private companies. Price says the company will continue to be active in the acquisition arena in 2007.

Another shale play that has slowly begun to increase in popularity next to the Barnett is the Woodford Shale in southeastern Oklahoma. Newfield Exploration Co. holds the first-mover advantage in this play, but Devon is cautiously moving forward with its position of some 90,000 acres. It planned to exit 2006 with four rigs running there and is regarding the play with cautious optimism before moving forward with potential acquisitions.

Ensuring the various constituent interests are educated about the drilling process, the limited environmental footprint, the benefit to the community at large and maintaining close communication with elected officials are the most difficult things.

— Brad Foster, Vice President, General Manager, Devon Energy's Central Division

"We're just starting to get a significant data set together," Foster says. "The problem with shale plays is that you need time to put wells on production to begin to understand what your decline rates are going to be. The longest a well in the Woodford has been on production for us has been about a year."

The Alabama shales are also beginning to grow in popularity, with Chesapeake recently announcing a partnership with Energen Resources Corp. after Energen sold a 50% interest in its 200,000 acres in various shale plays in Alabama. The companies plan to form an area of mutual interest on the acreage to develop shale plays throughout Alabama.

As companies get involved with shale plays, they become increasingly aware they are operating in a play unlike any they have seen.

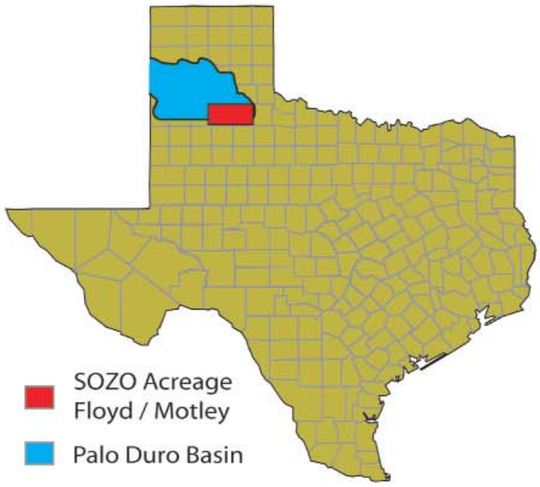
"The hardest thing about operating in the shale is the conventional wisdom you learned in college and in the oilfield over the years doesn't necessarily work in the shale," Foster says. "You almost have to retool your skill sets and your way of thinking because it doesn't always work the way conventional reservoirs work."

Price says the difficulties that arise operating in the shales are no different than those that arise working anywhere else.

"Ensuring the various constituent interests are educated about the drilling process, the limited environmental footprint, the benefit to the community at large and maintaining close communication with elected officials are the most difficult things," he says. ■

SOZO ENERGY, LP

Palo Duro Basin Farmout Opportunity in Floyd and Motley counties, Texas



SOZO Energy, LP has engaged **Energy Spectrum Advisors Inc.** to solicit farmout proposals for approximately 30,562 net acres in the Palo Duro Basin in Floyd and Motley counties, Texas.

The Company is seeking a well-funded operating partner with significant drilling experience in shale or other unconventional gas reservoirs.

Highlights:

Large, unconventional gas basin

The Company views the Palo Duro Basin as a large, unconventional, basin-centered gas field similar to the Barnett Shale with significant gas in place. The analysis was prepared by Netherland, Sewell and Associates, Inc. (NSAI). Current and former Palo Duro Basin operators support this view. The primary targeted horizon is the Lower Penn (Atoka) Shale, with additional potential in shallower formations.

Broad, relatively contiguous acreage position

SOZO has assembled a broad, relatively contiguous acreage position covering 37,671 gross acres (30,562 net). SOZO has meticulously selected this acreage based on its geologic potential as evaluated by NSAI, lease terms, royalty burdens, and proximity to gas pipelines.

Early entry with limited competition

The Palo Duro Basin is in the early stages of unconventional gas development. The SOZO farmout opportunity provides an opportunity for early entry into the play with a premier acreage position and the opportunity for expansion.

Acreage and Lease Term Data

County	Total Sections	Acres Under Lease Gross	Acres Under Lease Net	Avg. Rem. Term (Yrs) Primary+Extension	Avg. Rem. Term (Yrs) Ext.	% of Sections w/Extensions
Floyd	55	27,254	22,256	7.3	4.5	93%
Motley	23	10,417	8,306	5.6	3.1	74%
	78	**37,671**	**30,562**	**6.4**	**3.8**	**87%**

Strong commitment to the area

SOZO has additional holdings in the Palo Duro Basin and a vested interest in its development. The Company currently has an overriding royalty interest in over 500,000 acres, with the right to participate in 350,000 acres in the area. These additional interests afford SOZO certain rights to additional Palo Duro data.

High net revenue interest (NRI)

SOZO's gross net revenue interest averages 81%.

ENERGY SPECTRUM

Please direct all inquiries to:

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2006 SHALE M&A

Est. Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Quarter	Comments
$2,200	Devon Energy Corp.	Chief Holdings LLC	2	Purchased assets in the Barnett Shale, Texas, gaining proved reserves of 617 billion cubic feet equivalent.
$845	Chesapeake Energy Corp.	Four Sevens Oil Co. Ltd.; Sinclair Oil Corp.	2	Bought 39,000 acres in the Barnett Shale, Texas, gaining production of 30 million cubic feet equivalent.
$796	Chesapeake Energy Corp.	Seven private companies	1	Acquired assets in Barnett Shale, South Texas, Permian Basin, Mid-continent and East Texas, gaining proved reserves of 264 billion cubic feet equivalent.
$435	Range Resources Corp.	Stroud Energy Inc.	2	Bought company, gaining assets in Oklahoma and Texas with production of 33 million cubic feet equivalent per day, half of which is from Barnett Shale acreage.
$181	Chesapeake Energy Corp.	Dallas/Fort Worth International Airport	3	To lease 18,000 net acres prospective for Barnett Shale gas, gaining possible reserves of 470 billion cubic feet.
$110	XTO Energy Inc.	Peak Energy Resources	2	Bought company, gaining Barnett Shale assets in Hood, Parker and eastern Erath counties, Texas, with proved reserves of 64 billion cubic feet.
$87	Chesapeake Energy Corp.	Undisclosed	2	Bought unproved Barnett Shale acreage.
$30	Bankers Petroleum Ltd.	Vintage Petroleum	2	Bought shale gas acreage in various U.S. basins.
$28	Petrosearch Energy	Harding Co.	1	Formed a joint venture in the Barnett Shale.
$27.5	Cadence Resources	OIL Energy Corp.	1	Bought producing assets in the Antrim Shale gas play.
$11.5	TBX Resources	Earthwise Energy Inc.	3	Bought assets in the Barnett Shale.
$5.5	Dune Energy Inc.	Voyager Partners Ltd.		Bought Barnett Shale leaseholds in Denton County, Texas.
$5	Parallel Petroleum	Undisclosed	1	Bought interests in the Barnett Shale.
$3.4	Approach Resources Inc.	Hallador Petroleum	2	Bought an Albany Shale prospect in Kentucky.
$3	Nitro Petroleum Inc.	JMT Resources Ltd.	1	Bought a 50% interest in JMT's projects.
$1.2	Lexington Resources Inc.	Dylan Peyton LLC	1	Bought Barnett Shale acreage in Comanche City, Texas.
NA	Ascent Resources Plc	Norwest Energy	3	Bought interests in the West Virginia gas shale project.
NA	Cadence Resources	Undisclosed	1	Bought 64,000 acres in the New Albany Shale.
NA	Cadence Resources	Undisclosed	2	Bought interests in the New Albany Shale.
NA	Cadence Resources	Undisclosed	2	Bought interests in the Antrim Shale.
NA	Chesapeake Energy	Energen Corp.	2	Bought 140,000 acres in the Floyd Shale.
NA	Chesapeake Energy	Undisclosed	2	Bought 150,000 acres in the Barnett/Woodford Shale.
NA	Continental Resources	The Exploration Co.	2	Bought interests in the Marfa Basin in the Barnett/Woodford Shale.
NA	Crimson Exploration Inc.	Core Natural Resources	1	Bought 22,000 acres in the Barnett/Woodford play in Culberson City, Texas.
NA	Energen Corp.	Undisclosed	2	Bought 140,000 acres in the Floyd Shale.
NA	Forest Oil	Undisclosed	3	Bought interests in the Barnett Shale.
NA	Ignis Petroleum	Rife Energy Operating Inc.	1	Bought interests in the Barnett Shale play.
NA	Irvine Energy	Metro Group	3	Bought interests in the Chattanooga Shale in Kansas.
NA	Marathon Oil Corp.	Undisclosed	2	Bought 200,000 acres in the Bakken Shale play in North Dakota and Montana.
NA	Maverick Oil & Gas Inc.	RBE LLC	1	Bought a 13.33% interest in RBE LLC.
NA	Morgan Creek Energy	Pathways Investments	3	Bought interests in the Barnett Shale play.
NA	Nova Energy	Rife Energy Operating Inc.	3	Bought interests in the Barnett Shale.
NA	Pilgrim Petroleum	Undisclosed	3	Bought acreage in Clay County, Texas.
NA	Pogo Producing	Undisclosed	2	Bought 46,000 acres in the Bakken Shale play in North Dakota.
NA	Quest Oil Corp.	Gaither Petroleum	1	Bought interests in Barnett Shale acreage.
NA	Richey Ray Management	Lexington Resources	2	Bought interests in the Barnett Shale.
NA	Storm Cat Energy	Undisclosed	1	Bought acreage in the Fayetteville Shale play.
NA	TBX Resources	Undisclosed	2	Bought Barnett Shale interests.
NA	Unicorp Inc.	La Mesa Partners	1	Bought 2,500 acres in the New Albany play.
NA	Universal Property	L&R Energy Corp.	2	Bought Barnett Shale interests.
NA	US Energy Holdings	Taylor Exploration	1	Bought acreage in Crockett County, Texas.
NA	Westside Energy	Undisclosed	3	Bought interests in Barnett Shale acreage.
NA	Wynn-Crosby Energy Inc.	Undisclosed	1	Bought 2,600 acres in the Barnett Shale.
NA	XTO Energy Inc.	Undisclosed	2	Bought 166,000 undeveloped acres in the Barnett Shale.

Source: Natexis Bleichroeder Inc., John S. Herold Inc.

> WE EXPECT MORE
DYNAMIC
In an ever-changing world, the critical variables of our business, from commodity prices to future growth plans, are constantly in motion. At XTO, our leadership provides the dynamic decision-making to meet the dynamic challenges. It's a real-time advantage. WWW.XTOENERGY.COM
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