New and Emerging Unconventional Gas Plays and Prospects

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The outlook for domestic natural gas production rests greatly on how successful industry is in finding and aggressively developing new and emerging unconventional gas resources, as introduced in the first two articles of this series. As such, it is instructive to recognize that considerable differences of opinion exist on the future likelihood of establishing new, large unconventional gas plays and prospects. This article, the third in the series, presents our views on this important topic.

One view for future domestic natural gas production, as thoughtfully and clearly expressed in a recent article, is that the outlook is perilous: "It is unlikely that a new onshore gas play, either conventional or unconventional, will be discovered in the U.S. or Canada that will provide significant new supplies. . . . .This is a perilous situation because the most prolific of these resources, including the Barnett Shale, are already in relatively mature stages of development." (Berman, World Oil, June 2007)[1]

A contrary view, as set forth in this article and as supported by numerous examples of industry's creative pursuit and development of new unconventional gas resources, is that the outlook is promising, assuming a renaissance in unconventional gas technology research, investment and progress.

Where Are the New Plays, Prospects and Resources? The questions pursued in the article include - - *Are there any significant size, prolific unconventional gas plays left to find? Are the remaining unconventional gas resources mostly low quality and thus uneconomic? Are the existing unconventional plays so mature that little is left? Is it time to stop drilling for domestic unconventional gas and turn to LNG as the gas supply option for the future?*

These are large questions, with significant implications for domestic E&P companies, for LNG importers, and for U.S. consumers, larger than can be fully addressed in this series of articles. However, to provide some insights and "grist for the mill", this article will attempt to summarize and provide examples of our view that substantial new supplies of unconventional gas remain, sufficient to fill a significant portion of the gap resulting from declining conventional natural gas supplies.

So, where are the new sources of unconventional supplies, particularly the emerging plays and prospects? In this article we will introduce a number of these new plays and prospects, recognizing that exploration will prove some of these to be "dry holes", while others, with the aid of advances in unconventional gas technology, will likely emerge as productive plays. In addition, this article will emphasize the importance of looking internally at the already discovered plays for opportunities to more intensively develop the sizable, often bypassed unconventional gas resource. We start with a look at the currently most high visibility unconventional gas resource - - gas shales, Figure1.

New and Emerging Gas Shale Plays. Combining innovative drilling and stimulation technology with a large resource potential has allowed the Barnett Shale of the Fort Worth Basin to generate 2 Bcf of daily production - - sparking the current interest in evaluating and pursuing gas shales, a resource until recently categorized a reservoir source rock or seal. Two emerging gas shale plays, the Fayetteville and the Woodford shales, have also reached significant levels of production. For example, as of April 30, 2007, Southwestern Energy, the primary producer in the Fayetteville play, has increased its production from the play from 50 MMcfd to 200 Mcfd in one year's time, Figure 2, and collapsed the initial "learning time" for this play to two years Figure 3. Southwestern believes there is potential for 8,000 drilling locations in the Fayetteville Shale and 11 Tcf of potentially recoverable resource. Newfield Exploration Co., the primary producer in the Woodford Shale, estimates that this play also has potential for significant volumes (3 to 6 Tcf) of recoverable gas. With new techniques such as long horizontal wells and advanced slick-water fracturing, producers have been able to make plays like the Woodford and Fayetteville shales economically productive. Still, much remains to be learned about the favorable (and less favorable) geologic settings for these plays as well as the optimum drilling and completion practices (Toal, 2007).[2]

Now, the search is on for the next Barnett, Fayetteville, or Woodford shale play in places such as: (1) West Texas for Barnett and Woodford shales; (2) Alabama for the Conasauga Shale; (3) Appalachia for Marcellus and other gas shales; and (4) the Rockies for numerous shale deposits.

1. Barnett and Woodford Shales in West Texas. The Barnett and Woodford shales in the Permian Basin are thicker and generally deeper than their Mid-Continent counterparts. Here, the Barnett Shale ranges from 200 to 800 feet thick at depths between 5,000 and 15,000 feet. The Woodford Shale reaches 400 feet of thickness in the heart of the play. The organic content of these shales is high, with estimates of 4 to 7% Total Organic Carbon (TOC) providing an estimated gas in-place of several hundred Bcf per square mile in favorable areas (Riestenberg).[3] The major unresolved issues are - - *do these shales have sufficient permeability; can they be effectively stimulated; and will the wells be sufficiently productive to cover high D&C costs of $3 million for a vertical well and $4.5 million for a horizontal well?*

As of the beginning of 2006, more than 1.3 million acres had been leased for these two shale plays. The leased acreage is concentrated in Reeves and Culberson Counties, with the deeper and thicker shales occurring in the center and western parts of Reeves County. Conoco-Phillips, Chesapeake and Encana currently own large portions of the leased acreage. Still, it was the small independent, Alpine, Inc. (operating as K2X in Texas), that took the risk to establish the productivity of these West Texas shales (Williams, 2006)[4]. Until results are bolstered by additional test wells, we will not know whether or not the large gas-in-place in the West Texas Barnett and Woodford shales can be exploited economically.

2. Conasauga Shale in Alabama. Leasing and drilling for the middle Cambrian-age Conasauga Shale is underway in St. Clair and Etowah Counties in northeastern Alabama. The Conasauga Shale is several thousand feet thick (gross) due to the highly folded and faulted nature of the productive area of the play, potentially making it difficult to develop. In February 2007, the Alabama State Oil and Gas Board established 25,000 acres in northern St. Clair County as a new gas shale field named Big Canoe Creek. Dominion Black Warrior, Inc. with 13 wells (each with relatively modest test rates) is the primary developer in this field. Energen Resources Corporation has drilled three wells just outside the field boundary. It is still too early to determine whether this play will be a major gas shale play or an economic disappointment (OGJ 2007)[5] (Alabama State Oil and Gas Board)[6].

3. Marcellus Shale in Pennsylvania and New York. The Devonian-age Marcellus shale in eastern Pennsylvania and New York is typically found at depths of 5,000 to 8,000 feet with 75 to 200 feet of net pay. The shales are organically rich and thermally mature with TOC's near 5% and vitrinite reflectance values (Ro) averaging 1 to 2%. Range Resources has drilled 27 wells in the Marcellus Shale and expects EURs of 0.8 Bcf per well from its initial set of wells. Range is experimenting with Barnett-like horizontal wells with slick-water fractures that, while more expensive, are expected to greatly increase productivity. Within their 500,000 acre Marcellus Shale leases holding, Range projects an unrisked resource potential of 2.5 to 5 Tcf. (Williams, 2007)[7] (Brown, 2007)[8] (USGS, 2006)[9]

4. Gas Shale Activity in the Rockies. Numerous Cretaceous and late Carboniferous-age shales exist in the Rockies gas basins. With the growing interest in gas shales, it seems that every basin with a feasible shale resource is being explored. In line with its "early-mover" reputation, Bill Barrett Corp. has initiated its Yellow Jacket Shale Gas Project in southern Colorado and Utah, targeting the Pennsylvanian Gothic Shale between 5,500 and 7,500 feet. Barrett estimates 800 Bcfe of unrisked potential on its 63,000 (net) acre lease, expecting EURs of 1 to 3 Bcf per well.

Numerous producers are also exploring the potential of the Cretaceous-age Baxter Shales in the Green River Basin. Questar has drilled or re-completed a total of 18 wells in the Baxter and plans to drill 10 more in 2007, at depths ranging from 10,000 to 13,500 feet. One of the planned wells will involve a horizontal completion. Kodiak Oil and Gas Corporation's NT Federal #1-33 Baxter Shale well tested at 2 MMcfd of gas plus excess water. This $4.5 million well was completed with a nine stage frac. Kodiak is planning on drilling five additional wells in the vicinity of the NT Federal well.

New and Emerging Coalbed Methane Plays. Most of the higher quality, easier to produce coalbed methane plays have been found. What remains are the deeper coals, the lower rank coals and the opportunity to more intensively develop existing plays. Notable are: (1) the deep coals of the Greater Green River and Piceance basins, estimated to hold hundreds of Tcf of gas in-place; (2) the lower rank, Tertiary-age coals along the Gulf Coast; and (3) additional development of the already discovered Raton, San Juan and Uinta basin coals with infill wells, re-stimulation and enhanced coalbed methane (ECBM).

1. Green River and Piceance Basin CBM. The coalbed methane in the Green River and Piceance basins has long been noted for two things-- the vast in-place resource and their considerable depth. Estimates put the in-place coalbed methane resource of the Green River Basin at 314 Tcf (Tyler et al., 1995)[10] and of the Piceance Basin at 84 Tcf (McFall et al., 1986)[11].

In the Piceance Basin, the Cameo coal (in the "Paludal" zone located below the Williams Fork (Mesaverde) tight gas sands) contains about 80% of the basin's CBM resource. During the 1980s and early 1990s, producers experimented with commingling production from these deep tight gas sands and coals, motivated, in part, by Section 29 tax credits. However, the high reservoir pressure and the increase in water production from completing the coals eventually discouraged this practice. More recently, Encana has reported completing the entire Williams Fork (Mesaverde) interval, including the lower "Paludal coal zone", using vertical wells and multiple fracs.

In the Green River Basin, 85% of the 314 Tcf coalbed methane resource occurs below 6,000 ft. Since the early 1990's, operators have attempted to tap into these deep coals through completions into multiple seams or through commingled completions of coals and overlying Mesaverde tight gas sands, all with limited success. Today, drilling for these coals is underway in the Atlantic and Pacific Rim projects, along the shallower flanks of the Washakie Basin.

At the Atlantic Rim project, Double Eagle Petroleum Co. has been the most active producer with about 165 wells drilled and with 120 wells planned for 2007. Recoveries are estimated at 1.0 to 1.2 Bcf per well, with D&C costs of $1 million per well. Pending final approval of an EIS filed for the Atlantic Rim, operators estimate that 1,800 wells may be drilled in the next five years. While the active drilling in the shallow Green River coals is encouraging, the ultimate fate of the CBM potential in the Green River Basin lies in the still to be explored deep coals.

2. Low Rank Tertiary Coals of the Gulf Coast. A large in-place coalbed methane resource exists in Gulf Coast Tertiary coals, stretching from the Florida panhandle to the Texas Gulf Coast, Figure 4. One study (Warwick, et al., 2004)[12] sets the in-place resource at 4 to 8 Tcf; our independent mapping and resource assessment puts the size of this resource much higher. Of this, 3.4 Tcf may be recoverable (Potential Gas Committee, 2005)[13]. Prospective coals occur at depths of 1,500 to 5,000 ft depth with more mature, gas rich coals existing below 3,000 ft. Drilling has been limited to individual test pilots and significant production has yet to be established. However, leasing has been active, with over 400,000 acres leased to date.

3. Enhanced Coalbed Methane (ECBM). BP's Tiffany (N_2) and Burlington's Allison (CO_2) San Juan Basin ECBM pilots, conducted in the early 2000's, demonstrated the potential for ECBM to boost production. At the Allison test, involving 16 production wells and 4 CO_2 injection wells, production increased from about 700 Mcfd per well prior to CO_2 injection to a peak of about 3,500 Mcfd per well after CO_2

injection, Figure 5. However, because numerous other well enhancements were conducted during the CO_2 injection test, only about one-third of the increase may be due to ECBM. The test also experienced an initial 50% loss in CO_2 injection capacity, which appeared to improve over time. In our view, ECBM will likely remain a lower priority until the U.S. enacts carbon credits for storing anthropogenic CO_2. Work by Advanced Resources International (Reeves, 2003)[14] indicates that with ECBM, 90 Gt of CO_2 could be ultimately sequestered in domestic coal seams. To better understand this resource, the U.S. DOE is sponsoring a series of field tests involving CO_2-ECBM and CO2 sequestration.

New and Emerging Tight Gas Sand Plays. With the benefits of expanding geological knowledge, improved well completion technology, and a willingness to take risks, industry continues to find and establish new tight gas sand plays as well as revitalize previously discovered plays. Notable in this group are: (1) the Lance tight gas sand play at Pinedale in southwestern Wyoming; (2) the deep Bossier gas play in East Texas; and (3) the Mesaverde tight gas sand play in the Piceance and Uinta basins. Importantly, all three of the unconventional gas plays offer promise for intensive resource development (Kuuskraa, 2004)[15].

1. Lance/Mesaverde Play, Pinedale Field, Green River Basin. Gas production has climbed rapidly for the Lance/Mesaverde tight gas play, now approaching a Bcf per day. The Lance/Mesaverde reservoirs contain stacks of channel-fill sandstones, involving 20 to 70 individual sand packages and providing net pay of 300 to over 1,000 feet. Three dimensional seismic is helping identify “fairways” in these complex stacked reservoirs and advanced core and log analysis is providing a more complete geologic model of the productive sands in the field. Operators have determined that a greater number (a dozen or more) of smaller-size (about 100,000 lbs of proppant) stimulations help a well achieve contact with more sands than the previous smaller number of larger-size stimulations, Table 1.

The low-permeability of the Lance-Mesaverde sands and their lenticular nature allow considerable down-spacing for wells without significant loss in well productivity. For example, Ultra Petroleum conducted a study on 170 Pinedale wells spaced at 10 acres. Little to no well interference was noted, opening up the potential for closer, more optimal well spacing for this tight gas sand play. Well productivity continues to increase, rising from less than 5 Bcf per well in the late 90s to nearly 9 Bcf per well for more recent completions, Table 2.

Ultra, the largest leaseholder on the Pinedale Anticline, has drilled and placed on production 168 wells. With over 5,000 drilling locations, Ultra believes there may be 23 Tcf of ultimate gas recovery (gross) within their holdings. Shell, with 82 Bcf of Pinedale production last year, has participated in drilling more than 260 wells. Shell is pursuing increased efficiency in well completions, with up to 8 frac stages per day per well reported recently. Shell has also undertaken individual sand pressure tests to determine sand continuity and optimal wells spacing. Questar, with 195 producing wells, believes that, with down-spacing, it still has over 900 undrilled locations within their core acreage. The Pinedale Field has already produced over a Tcf of gas to date. With all three major operators reporting increased drilling in 2007, Pinedale is poised to become Wyoming's largest producing natural gas field and one of the largest in the U.S.

2. Deep Bossier Play, East Texas. The Deep Bossier is a high pressure, high temperature tight gas sand reservoir, occurring at depths generally greater than 15,000 feet. It is a Jurassic-age continental slope depositional system on the western flank of the East Texas Basin. The resource is characterized as containing thin, overpressurized, low water saturation, low permeability sands within a thick package of marine shales. The overall shale/sand package ranges in thickness from 1,000 to 2,500 ft, with 25 to 100 ft of net sand. Pressure gradients range from 0.6 to 0.8 psi per foot and matrix permeabilities are on the order of 5 micro-darcies. Wells in this difficult, deep play currently cost between $8 (at 16,000 ft) and $12 million (at 18,500 ft) to drill and complete. However, it is anticipated that well costs will come down as drilling practices evolve. While operators typically report EURs from 5 to 7 Bcf per well, a handfull of wells have EURs in excess of 20 Bcf.

Three main operators are developing this emerging tight gas sand play. Gastar's primary asset is the Hilltop Resort Field in which they hold 16,350 net acres. Gastar has drilled 16 Deep Bossier wells in the field that currently produce 20 MMcfd. They estimate a recoverable resource of 350 Bcfe within their lease acreage. EnCana and Leor have joint working interests in the 190,000 acre Amoruso Field which they estimate to hold multiple Tcf of recoverable gas. Production is at 200 MMcfd and may reach 350 MMcfd by the end of 2008, Figure 6. Notably, Encana/Leor have drilled some truly exceptional wells in the Amorusa Field, including three that produced over a Bcf in their first 30 days. ConocoPhillips is active in the Savell and Rainbolt Ranch fields where the company holds about 200,000 acres, produces about 200 MMcfd, with plans to increase drilling this year, and reports impressive gas production rates, Table 3.

The Deep Bossier play is still in its early days of exploitation. If the Savell, Hilltop Resort, Amorusa, and Rainbolt Ranch fields continue their success, the Deep Bossier has the potential to become one of the larger domestic tight gas sand plays with production of a Bcf (or more) per day.

3. Mesaverde Play, Piceance and Uinta Basins. The Williams Fork-Mesaverde play in the Piceance Basin, introduced in Part 2 of this series, is a growing Rockies tight gas sand play that produced 145 Bcf of gas in 2006. A geologically analogous tight gas play in the Uinta Basin, the Wasatch-Mesaverde, is still in early development. These are stacked, lenticular sand plays deposited in fluvial and coastal environments. The reservoirs consist of a 3,000 to 4,000 ft thick package of sands, shales, and coals, with a series of 20 to 40 ft thick point bar sand deposits that terminate abruptly at low-permeability boundaries.

The Piceance Basin Williams Fork-Mesaverde play has seen significant innovations during its development. For example, Williams Co., the dominant producer in the play, is using FlexRigs which are capable of drilling up to 22 wells from a single pad, Figure 7. They report drilling times of less than 10 days with this rig, compared to 20 days to drill a well five years ago. Well fracturing operations have also been centralized, with up to 65 wells on 6 pads fractured from a single location. Williams is also actively pursuing its largely undeveloped Piceance Highlands properties holding 3,700 undeveloped drilling locations and 3 Tcf of resource.

The Uinta Basin Wasatch-Mesaverde play is still in the process of being defined. EOG has conducted coring studies that point to over 200 ft of pay in a 900 ft interval versus only 40 feet previously identified by open-hole logs. EOG now estimates that the play contains up to 250 Bcf per section of gas in-place, five times higher than estimated from logs, Figure 8. Completion and treatment of as much of the sand in the Wasatch-Mesaverde interval as possible is a key technology step. For example, Bill Barrett Corp. has been stimulating an average of 10 multi-pay zones across an interval of about 2,900 ft in their Peters Point Field wells. Their average well has produced 0.9 Bcf in the first 12 months. Within their Uinta acreage, Bill Barrett Corp. has identified 250 to 300 drilling “sweet spots” where their multiple pay zone stimulation practices are expected to provide EURs of 2 to 3 Bcf per well, significantly higher than achieved by earlier wells in this area.

Productive Next Steps. Space constrains our review and discussion of new and emerging unconventional gas plays. Numerous other potential opportunities, such as the tight gas sands of the Columbia Basin, the coalbeds of the Mid-Continent, and the gas shales of Alberta/British Columbia deserve attention. However, we will leave this for another day and another article.

What we would recommend as an important next step is a renewed emphasis on rigorously establishing the resource in-place for unconventional gas. Early visionary steps to quantify the gas in-place in tight gas sand plays were taken by USGS scientists (Law, Spencer, Fouch, and Johnson, among others) using the best of limited and difficult to interpret data. The data base is now considerably larger and today's log and core interpretation methods are superior. Our continuing work on unconventional gas resources convinces us that large volumes of unconventional gas resource remain. With technology, vision and persistence, these could be converted to recoverable reserves. This work also teaches us just how much we have still left to learn about the true size and nature of the unconventional gas resource and its economically prospective plays.

Table 1. Advances in Well Completion Practices: Pinedale, Lance/Mesaverde

Year Compl.	Number of Wells	Avg. Number of Perforations/ Stimulations	Avg. Proppant per Stimulation (lbs)	Avg. Gross Interval (ft)	Avg. Production, First 12 months (MMcf)
2000	3	5/5	275,000	2,400	0.6
2004	83	20/20	175,000	4,500	1.1
2006	161	40/15	100,000	5,000	1.0

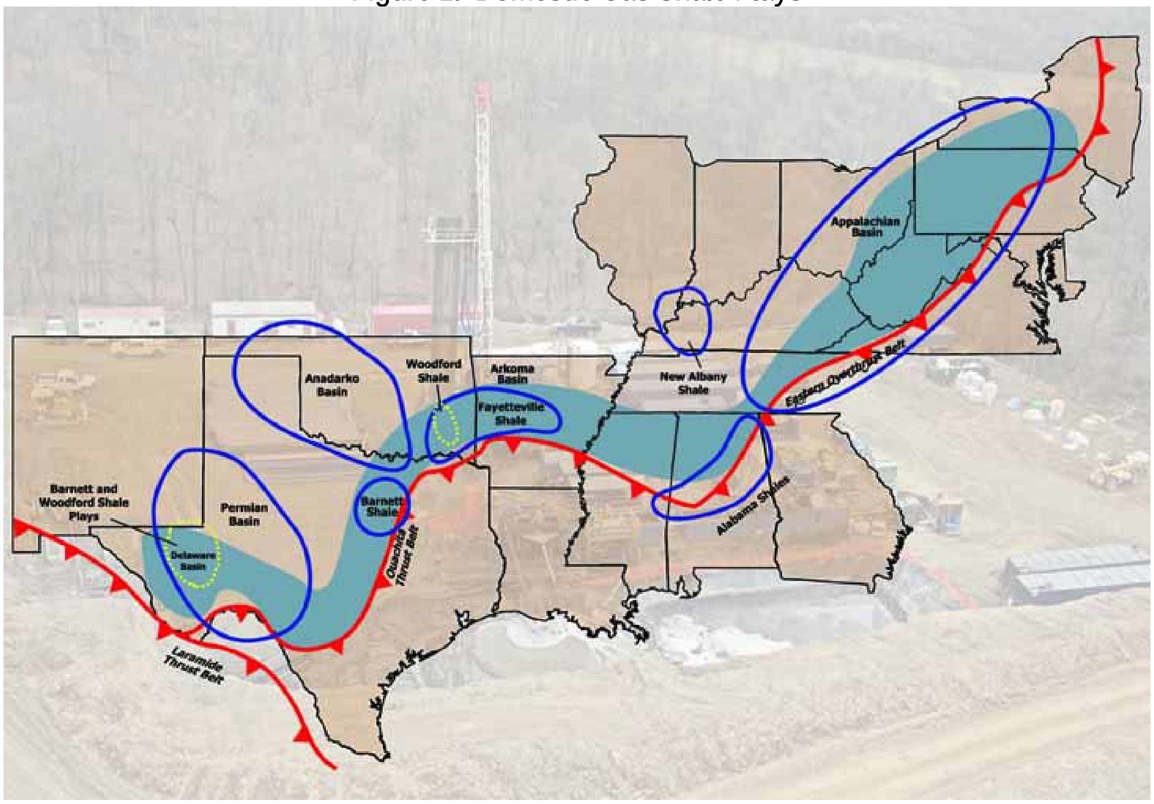
Table 2. Tight Gas Sand Well Performance: Pinedale, Lance/Mesaverde

	Total Wells	Successful Wells	EUR/Well (Bcf)	Success Rate (%)
1996-1999	9	9	4.6	100%
2000-2002	48	47	8.6	98%
2003-2005	222	217	8.7	98%

Table 3. Selected Savell Field Deep Bossier Wells

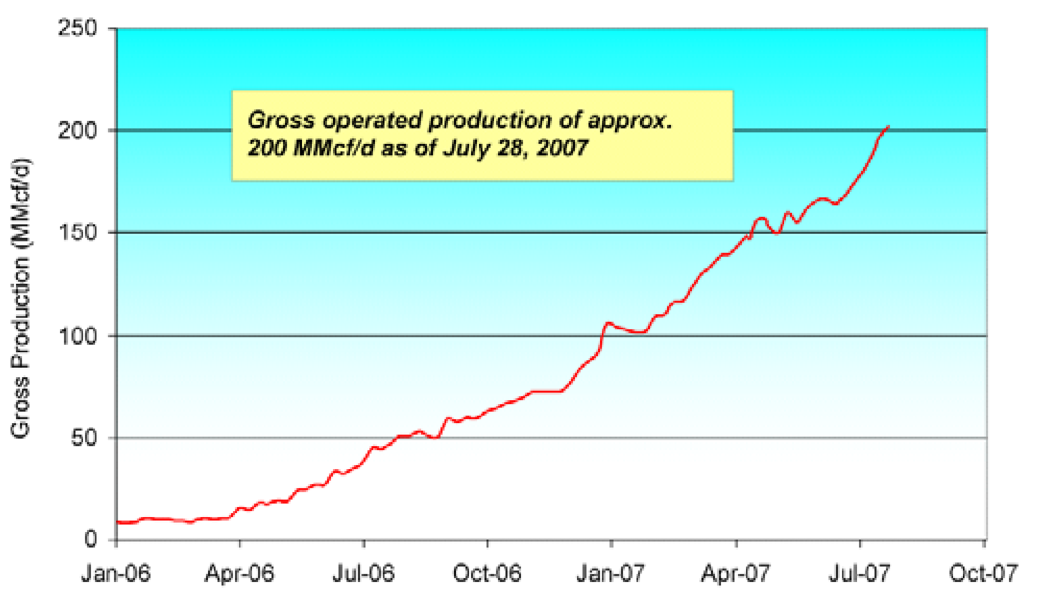
Compl. Year	Number of Wells	Cum. Recovery (Through Mar 07) (Bcf)	Avg. Peak Monthly Rate (MMcfd)
2004	2	24.4	19.8
2005	10	76.0	17.9
2006	7	0.03	14.8

Figure 1. Domestic Gas Shale Plays



Source: AAPG Explorer

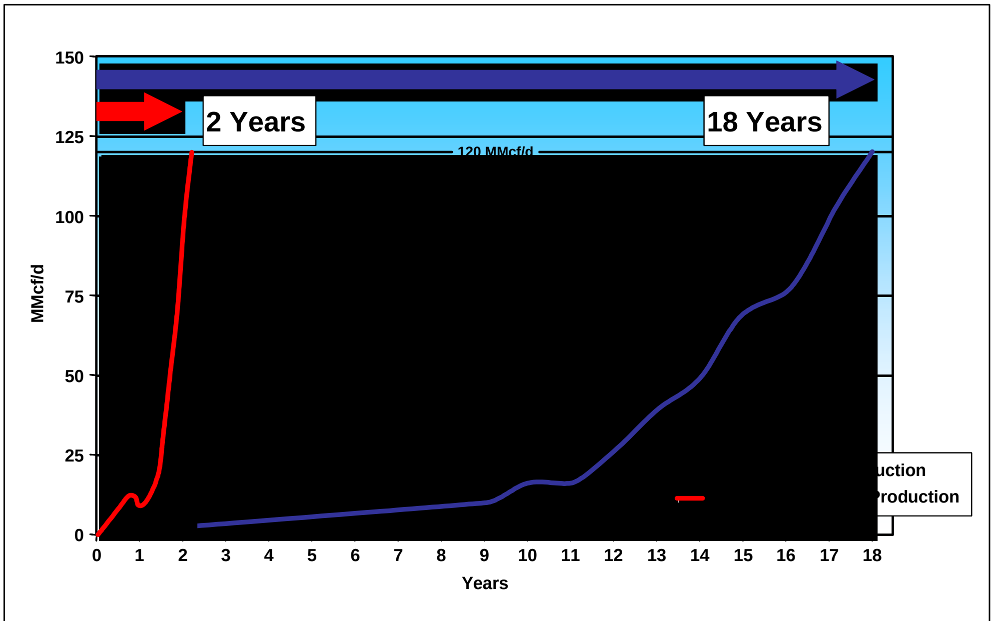
Figure 2. Fayetteville Shale: Gross Natural Gas Production (for Southwestern Energy)



Note: Data as of July 28, 2007

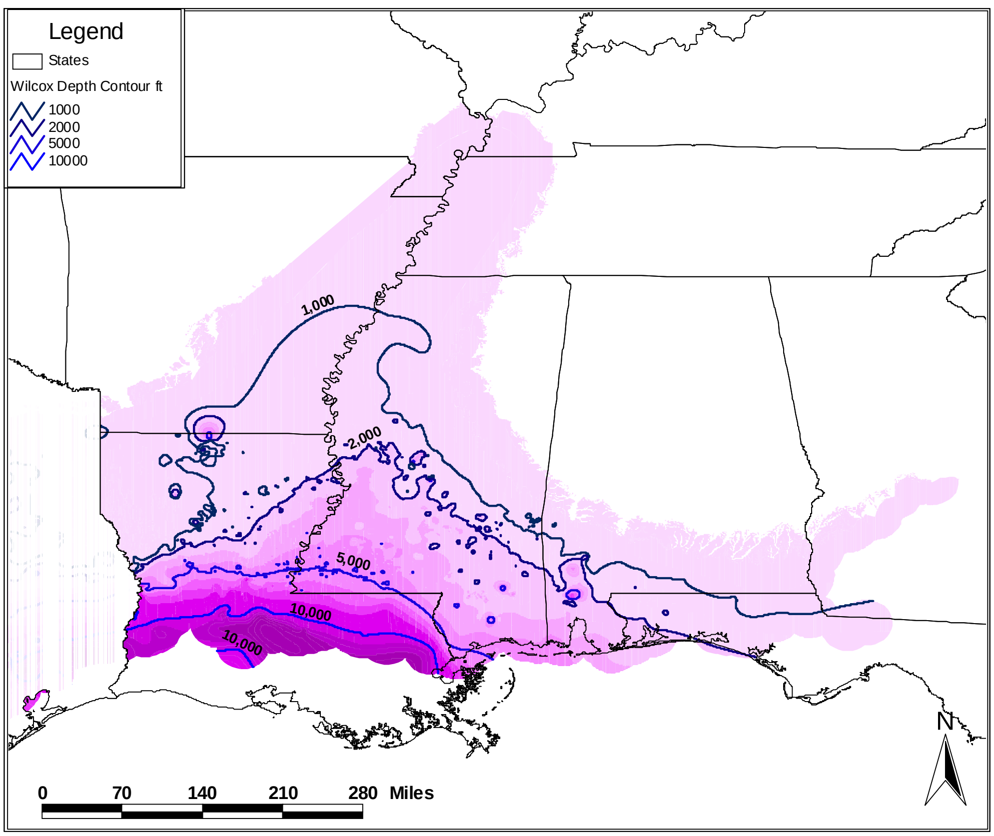
Source: Southwestern Energy, 2007

Figure 3. Fayetteville Production Growth Compared to the Barnett



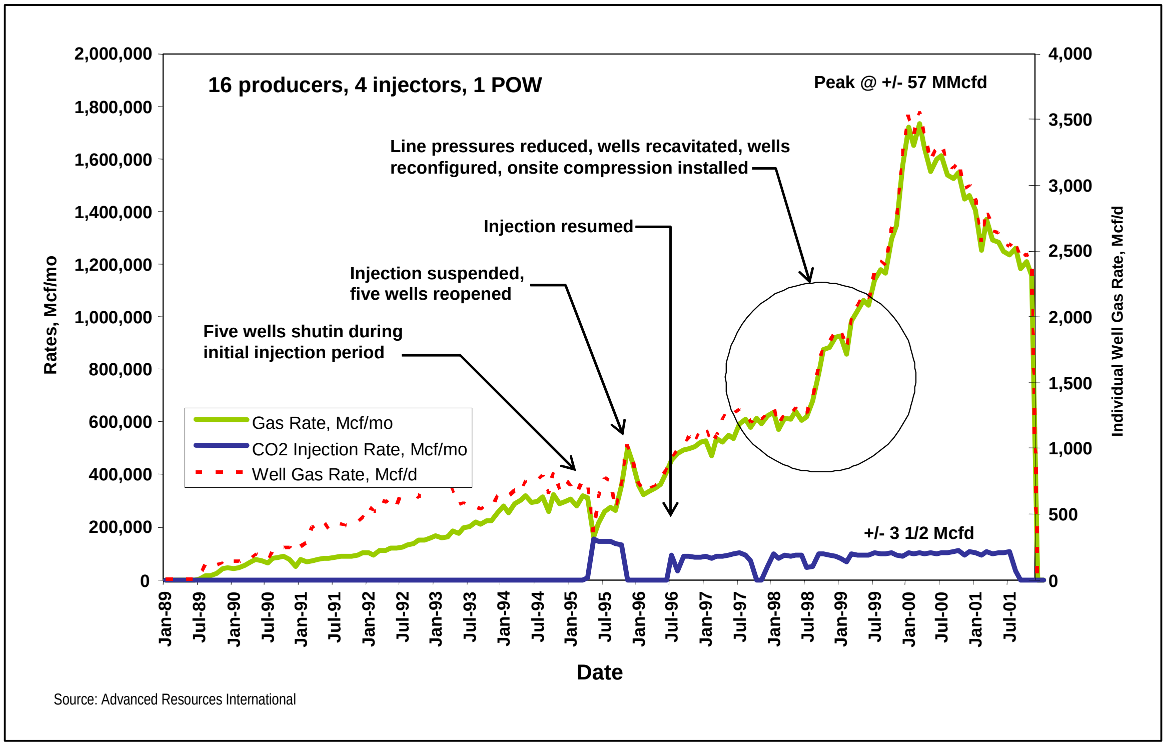
Source: Pickering Energy Partners

Figure 4. Gulf Coast Tertiary Coal Belt (Louisiana to Florida)



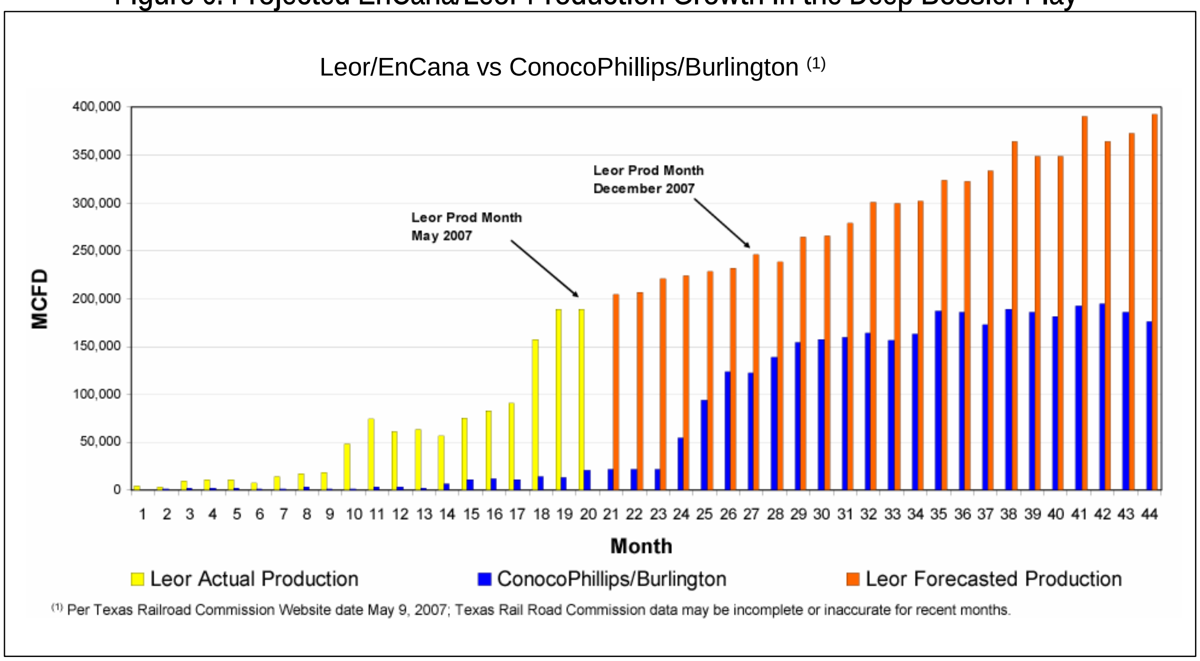
Source: based on data from http://pubs.usgs.gov/of/2000/ofr-00-0113/wlcxmaps.htm#1

Figure 5. San Juan Basin Allison Unit CO_2-ECBM Performance



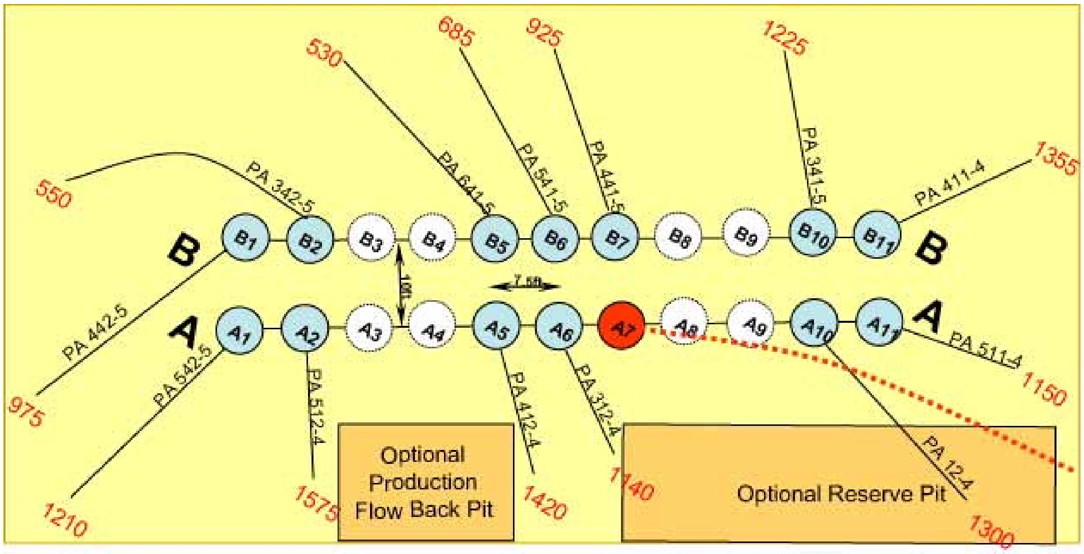
Source: Advanced Resources International

Figure 6. Projected EnCana/Leor Production Growth in the Deep Bossier Play



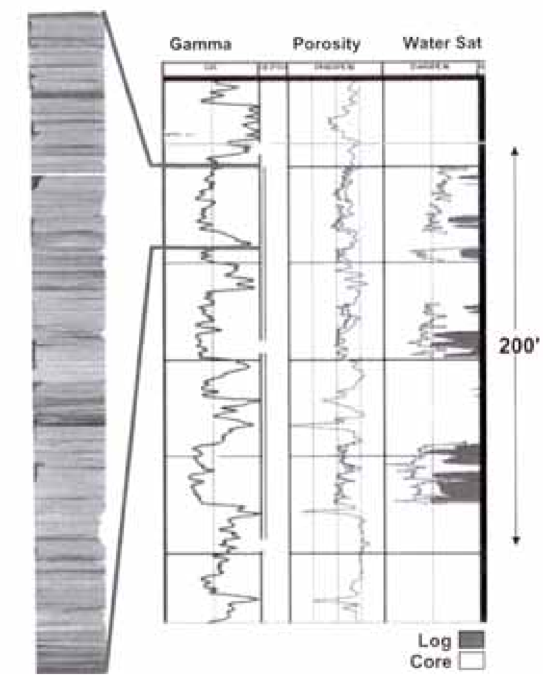
Source: Leor Energy, 2007

Figure 7. Drilling Multiple Wells from a Single Well Pad (Williams, Piceance Basin).



Source: Williams, 2007

Figure 8. Comparison of Log and Core Pay Assessment (EOG, Uinta Basin)



Source: EOG Resources, 2006

	Net Pay (Feet)	Porosity (%)	Water Sat. (%)	Bcf/ Section
Open Hole Log	41	9.3	55	42
900 Foot Oil-Based Core	216	8.6	45	250

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Acknowledgements

We would like to thank Peggy Williams for her personal correspondence in regards to the shale section of this article.

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