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Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays

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The information presented in this overview is based on the report Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays, which was prepared by INTEK, Inc. for the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. The full report is attached. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays

Background

The use of horizontal drilling in conjunction with hydraulic fracturing has greatly expanded the ability of producers to profitably recover natural gas and oil from low-permeability geologic plays—particularly, shale plays. Application of fracturing techniques to stimulate oil and gas production began to grow rapidly in the 1950s, although experimentation dates back to the 19th century. Starting in the mid-1970s, a partnership of private operators, the U.S. Department of Energy (DOE) and predecessor agencies, and the Gas Research Institute (GRI) endeavored to develop technologies for the commercial production of natural gas from the relatively shallow Devonian (Huron) shale in the eastern United States. This partnership helped foster technologies that eventually became crucial to the production of natural gas from shale rock, including horizontal wells, multi-stage fracturing, and slick-water fracturing.[1] Practical application of horizontal drilling to oil production began in the early 1980s, by which time the advent of improved downhole drilling motors and the invention of other necessary supporting equipment, materials, and technologies (particularly, downhole telemetry equipment) had brought some applications within the realm of commercial viability. [2]

The advent of large-scale shale gas production did not occur until Mitchell Energy and Development Corporation experimented during the 1980s and 1990s to make deep shale gas production a commercial reality in the Barnett Shale in North-Central Texas. As the success of Mitchell Energy and Development became apparent, other companies aggressively entered the play, so that by 2005, the Barnett Shale alone was producing nearly 0.5 trillion cubic feet of natural gas per year. As producers gained confidence in the ability to produce natural gas profitably in the Barnett Shale, with confirmation provided by results from the Fayetteville Shale in Arkansas, they began pursuing other shale plays, including Haynesville, Marcellus, Woodford, Eagle Ford, and others.

Although the U.S. Energy Information Administration's (EIA) National Energy Modeling System (NEMS) and energy projections began representing shale gas resource development and production in the mid-1990s, only in the past 5 years has shale gas been recognized as a "game changer" for the U.S. natural gas market. The proliferation of activity into new shale plays has increased dry shale gas production in the United States from 1.0 trillion cubic feet in 2006 to 4.8 trillion cubic feet, or 23 percent of total U.S. dry natural gas production, in 2010. Wet shale gas reserves increased to about 60.64 trillion cubic feet by year-end 2009, when they comprised about 21 percent of overall U.S. natural gas reserves, now at the highest level since 1971.[3] Oil production from shale plays, notably the Bakken Shale in North Dakota and Montana, has also grown rapidly in recent years.

To gain a better understanding of the potential U.S. domestic shale gas and shale oil resources, EIA commissioned INTEK, Inc. to develop an assessment of onshore Lower 48 States technically recoverable shale gas and shale oil resources. This paper briefly describes the scope, methodology, and key results of the report and discusses the key assumptions that underlie the results. The full report prepared by INTEK is provided in Attachment A. The shale gas and shale oil resource assessment contained in the INTEK report and summarized here was incorporated into the Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) within the Oil and Gas Supply Module (OGSM) of NEMS to project oil and natural gas production for the *Annual Energy Outlook 2011* (*AEO2011*). EIA also anticipates using the assessment to inform other analyses and to provide a starting point for future work.

Scope and results

The INTEK shale resources report estimates shale gas and shale oil resources for the undeveloped portions of 20 shale plays that have been discovered (Table 1). Eight of those shale plays are subdivided into 2 or 3 areas, resulting in a total of 29 separate resource assessments. The total of 750 trillion cubic feet shown in Table 1 excludes three additional components of resources: proven reserves, inferred reserves in actively developed areas and un-discovered resources as estimated by the U.S. Geological Survey (USGS). The map in Figure 1 shows the location of the shale plays in the Lower 48 States.

Eighty-six percent of the total 750 trillion cubic feet of technically recoverable shale gas resources identified in Table 1 are located in the Northeast, Gulf Coast, and Southwest regions, which account for 63 percent, 13 percent, and 10 percent of the total, respectively. In the three regions, the largest shale gas plays are the Marcellus (410.3 trillion cubic feet, 55 percent of the total), Haynesville (74.7 trillion cubic feet, 10 percent of the total), and Barnett (43.4 trillion cubic feet, 6 percent of the total).

Table 1 also summarizes the INTEK shale report's assessment of technically recoverable shale oil resources, which amount to 23.9 billion barrels in the onshore Lower 48 States. The largest shale oil formation is the Monterey/Santos play in southern California, which is estimated to hold 15.4 billion barrels or 64 percent of the total shale oil resources shown in Table 1. The Monterey shale play is the primary source rock for the conventional oil reservoirs found in the Santa Maria and San Joaquin Basins in southern California. The next largest shale oil plays are the Bakken and Eagle Ford, which are assessed to hold approximately 3.6 billion barrels and 3.4 billion barrels of oil, respectively.

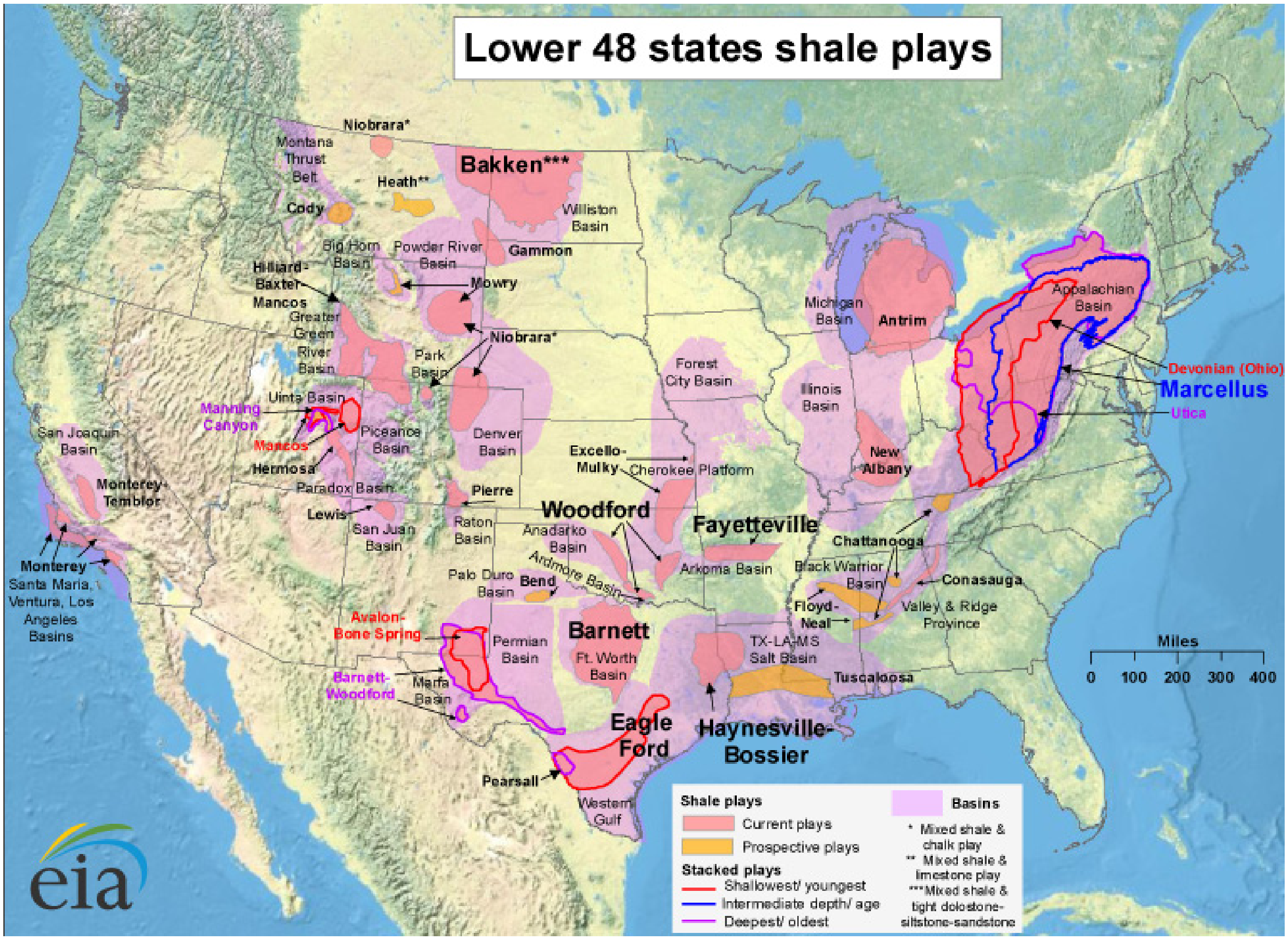
The 750 trillion cubic feet of shale gas resources in the INTEK shale report is a subset of the *AEO2011* onshore Lower 48 States natural gas shale technically recoverable resource estimate of 862 trillion cubic feet. The *AEO2011* includes 35 trillion cubic feet of proved reserves reported to the Securities and Exchange Commission (SEC) and the EIA, 20 trillion cubic feet of inferred reserves not included in the INTEK shale report, and 56 trillion cubic feet of undiscovered resources estimated by the USGS.

Table 1. INTEK estimates of undeveloped technically recoverable shale gas and shale oil resources remaining in discovered shale plays as of January 1, 2009

Onshore Lower-48 Oil and Gas Supply Submodule region	Shale play	Shale gas resources (trillion cubic feet)	Shale oil resources (billion barrels)
Northeast	Marcellus	410	--
	Antrim	20	--
	Devonian Low Thermal Maturity	14	
	New Albany	11	--
	Greater Siltstone	8	--
	Big Sandy	7	--
	Cincinnati Arch*	1	--
Subtotal		472	--
Percent of total		63%	--
Gulf Coast	Haynesville	75	--
	Eagle Ford	21	3
	Floyd-Neal & Conasauga	4	--
Subtotal		100	3
Percent of total		13%	14%
Mid-Continent	Fayetteville	32	--
	Woodford	22	--
	Cana Woodford	6	--
Subtotal		60	--
Percent of total		8%	--
Southwest	Barnett	43	--
	Barnett-Woodford	32	--
	Avalon & Bone Springs	--	2
Subtotal		76	2
Percent of total		10%	7%
Rocky Mountain	Mancos	21	--
	Lewis	12	--
	Williston-Shallow Niobraran*	7	--
	Hilliard-Baxter-Mancos	4	--
	Bakken	--	4
Subtotal		43	4
Percent of total		6%	15%
West Coast	Monterey/Santos	--	15
Subtotal		--	15
Percent of total		--	64%
Total onshore Lower-48 States		750	24

*Note: From previous EIA estimates and thus not assessed in the INTEK shale report.
Subtotals and total may not equal sum of components due to independent rounding.

Figure 1. Map of U.S. shale gas and shale oil plays (as of May 9, 2011)



Source U.S. Energy Information Administration based on data from various published studies.
Upeate: May 9, 2011

Methodology

The resource estimates shown in Table 1 were developed by INTEK from publicly available company data and commercial databases for wells and acreage currently in production. The estimates of technically recoverable resources shown in Table 1 are based on the area, well spacing, and average expected ultimate recovery (EUR) for each shale play or subportion of the play. An effective recovery factor has been applied which reflects: (a) a probability factor that takes into account the results from current shale gas activity as an indicator of how much is known or unknown about the shale play; (b) a recovery factor that takes into account prior experience in how production occurs, on average, given a range of factors (including mineralogy and geologic complexity) that affect the response of the geologic play to the application of best-practice shale gas recovery technology; and (c) resources in the play that have already been produced or added into proved reserves.

Estimates of technically recoverable shale gas resources are certain to change over time as new wells go into production and new technologies are developed. For example, the gas resource estimates in the INTEK shale report are predicated on the assumption that natural gas production rates for current wells covering only a limited portion of a play are representative of an entire play or play sub-area; however, across a single play or play sub-area there can be significant variations in depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content. As a result, individual well production rates and recovery rates can vary by as much as a factor of 10.

There is considerable uncertainty regarding the ultimate size of technically recoverable shale gas and shale oil resources, including but are not limited to the following:

- Because most shale gas and shale oil wells are only a few years old, their long-term productivity is untested. Consequently, the long-term production profiles of shale wells and their estimated ultimate recovery of oil and natural gas are uncertain.
- In emerging shale plays, production has been confined largely to those areas known as "sweet spots" that have the highest known production rates for the play. If the production rates for the sweet spots are used to infer the productive potential of entire plays, their productive potential probably will be overstated. The INTEK shale report mitigates this problem by differentiating the productivity of a play's sweet spot from the productivity for rest of that play.[8]

- Many shale plays are so large (e.g., the Marcellus shale) that only portions have been extensively production tested.
- Technical advancements could lead to more productive and less costly well drilling and completion.
- Currently untested shale plays, such as thin-seam plays or untested portions of existing plays, could prove to be highly productive.

Estimating the technically recoverable oil and natural gas resource base in the United States is an evolving process. For shale gas and oil, the evolution of resource estimates is likely to continue for some time. The size of the technically recoverable oil and natural gas resource base in the United States becomes evident only as producers drill into geologic deposits with oil and natural gas potential and attempt to produce from them on a commercial basis. As producers find plays to be more or less bountiful than expected, resource estimates are adjusted to reflect that information. As time passes and our knowledge of the resource base and future technologies and management practices improves, estimates of the technically recoverable resource base will be refined. Consequently, the resource estimates in the current report will be modified over time as more wells are drilled and completed, technologies evolve, and the long-term performance of shale wells becomes better established.

The estimates of shale oil and shale gas resources provided here represent a reasonable estimate of the resource potential for those shale plays for which public information is currently available. The potential impacts of the current uncertainty regarding shale gas resources on projected natural gas supply, consumption, and prices are described in the *AEO2011* Issues in Focus article, "Prospects for shale gas."[9]

Footnotes

[1] G.E. King, Apache Corporation, "Thirty Years of Gas Shale Fracturing: What Have We Learned?", presentation SPE 133456, SPE Annual Technical Conference and Exhibition (Florence, Italy, September 2010), www.spe.org/atce/2010/pages/schedule/tech_program/documents/spe1334561.pdf; and U.S. Department of Energy, "DOE's Early Investment in Shale Gas Technology Producing Results Today" (February 2, 2011), www.netl.doe.gov/publications/press/2011/11008-DOE_Shale_Gas_Research_Producing_R.html.

[2] U.S. Energy Information Administration, Drilling Sideways—A Review of Horizontal Well Technology and Its Domestic Application, DOE/EIA-TR-0565 (Washington, DC, April 1993), ftp://tonto.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/drilling_sideways_well_technology/pdf/tr0565.pdf.

[3] U.S. Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (Washington, DC, November 30, 2010), www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html.

[4] American Association of Petroleum Geologists, "Monterey Shale Gets New Look," Explorer, Vol. 31, No. 11 (No-vember 2010), http://www.aapg.org/explorer/2010/11nov/monterey1110.cfm.

[5] Additional information and comparisons of the SEC and EIA reserves can be found in the EIA report "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves, 2009" and a supplemental report "Top 100 Operators: Proved Reserves and Production, Operated vs Owned, 2009". http://www.eia.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html.

[6] HPDI, LLC production database, and Nehring Associates (NRG), Significant Oil and Gas Fields of the United States Database.

[7] The EURs presented in this report do not include natural gas plant liquids.

[8] In the INTEK report, the "sweet spot" portion of the formation is referred to as the "active area." The remaining portion of the formation that has seen little or no drilling activity is referred to as the "undeveloped area."

[9] U.S. Energy Information Administration, A*nnual Energy Outlook 2011*, DOE/EIA-0383(2011) (Washington, DC, April 2011), "Prospects for shale gas," www.eia.gov/forecasts/aeo/IF_all.cfm#prospectshale.

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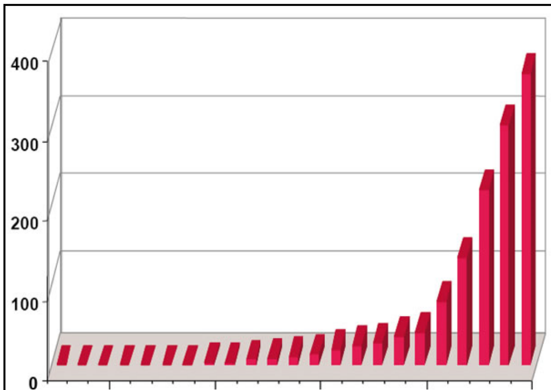
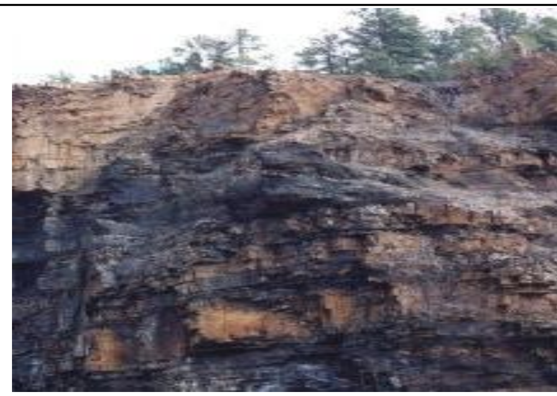
Attachment A

INTEK, Inc.

Review of Emerging Resources
U.S. Shale Gas and Shale Oil Plays





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Washington, D.C

Disclaimer

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List of Abbreviations & Acronyms

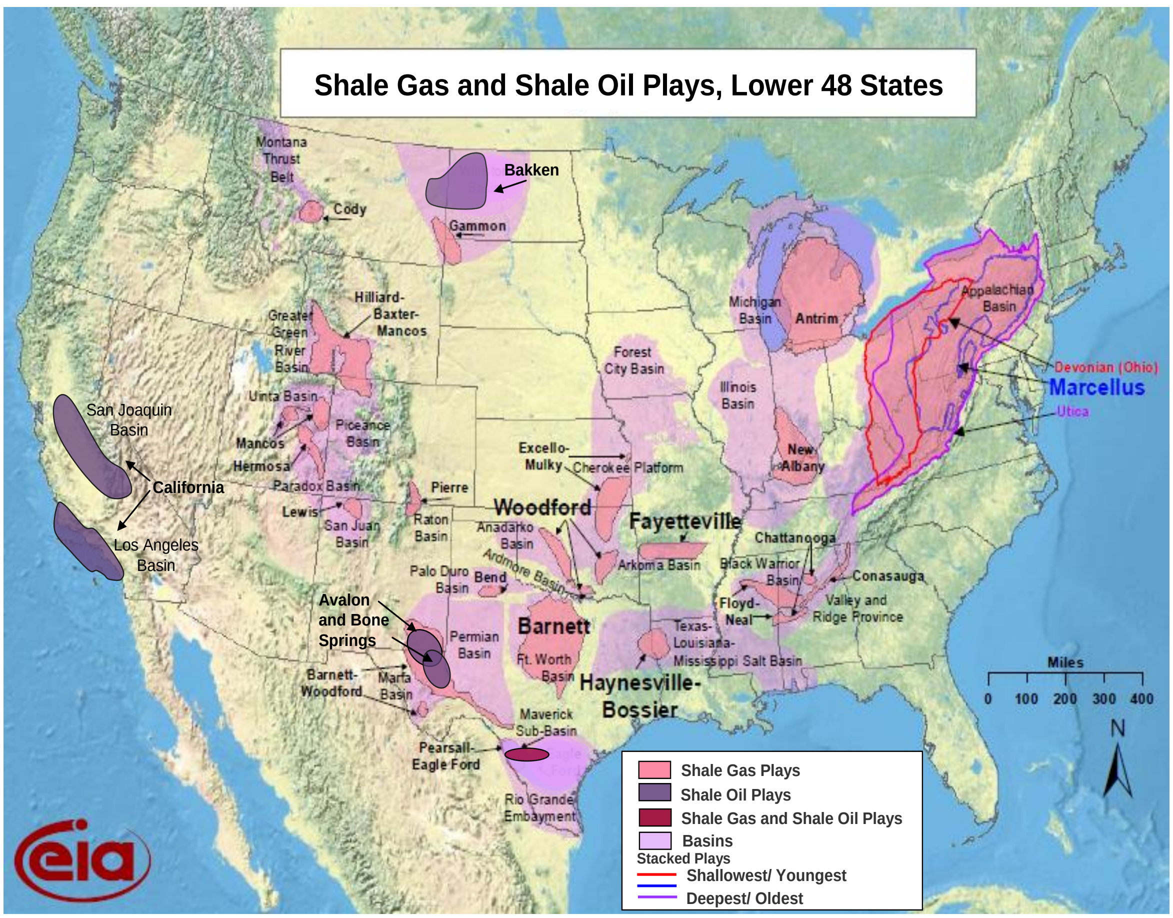
Abbreviation/ Acronym	Full Text
Bbbl	Billion Barrels
bbl	Barrel
BBO	Billion Barrels of Oil
BBOE	Billion Barrels of Oil Equivalent
Bcf	Billion Cubic Feet
Bcfe	Billion Cubic Feet of Equivalent
BOE	Barrels of Oil Equivalent
DOE	Department of Energy
EIA	Energy Information Administration
EUR	Estimated Ultimate Recovery
MBOE	Thousand Barrels of Oil Equivalent
MMBOE	Million Barrels of Oil Equivalent
Tcf	Trillion Cubic Feet
Tcfe	Trillion Cubic Feet Equivalent
TRR	Technically Recoverable Resources
USGS	United States Geological Survey

Executive Summary

The Energy Information Administration's (EIA) 2010 Annual Energy Outlook (AEO2010) discussed the growing importance of shale gas as a component of natural gas production. "…[T]he biggest questions are the size of the shale gas resource base (which by most estimates is vast), the price level required to sustain its development, and whether there are technical or environmental factors that might dampen its development". EIA's AEO2010 reference case estimate for the shale gas resource base was 347 trillion cubic feet (Tcf).

In recognition of the increasing contribution of shale gas production to the United States, in late 2010, a study was undertaken to review and update the resource base estimates for the U.S. shale gas resources as well as emerging shale oil plays. These plays are illustrated in Figure i.

Figure i U.S. Shale Gas and Shale Oil Plays



Shale Gas

Significant activities are underway in the United States to explore, develop, and produce America's shale gas and oil plays. The shale gas plays contain "fine grained, organic rich, sedimentary rocks. The shales are both the source of and the reservoir for natural gas" and oil. They are also defined by the "extremely small pore sizes [which] make them relatively impermeable to gas flow, unless natural or artificial fractures occur". A summary of the unproved discovered technically recoverable resources (TRR) is provided in the following Table.

Table i U.S. Shale Gas Unproved Discovered Technically Recoverable Resources Summary

Play	Technically Recoverable Resource		Area (sq. miles)		Average EUR	
	Gas (Tcf)	Oil (BBO)	Leased	Unleased	Gas (Bcf/ well)	Oil (MBO/ well)
Marcellus	410.34	…	10,622	84,271	1.18	…
Big Sandy	7.40	…	8,675	1,994	0.33	…
Low Thermal Maturity	13.53	…	45,844		0.30	…
Greater Siltstone	8.46	…	22,914		0.19	…
New Albany	10.95	…	1,600	41,900	1.10	…
Antrim	19.93	…	12,000		0.28	…
Cincinnati Arch*	1.44	…	**NA**		0.12	…
Total Northeast	**472.05**	**…**	**101,655**	**128,272**	**0.74**	**…**
Haynesville	74.71	…	3,574	5,426	3.57	…
Eagle Ford	20.81	…	1,090		5.00	…
Floyd-Neal & Conasauga	4.37	…	2,429		0.90	…
Total Gulf Coast	**99.99**	**…**	**7,093**	**5,426**	**2.99**	**…**
Fayetteville	31.96	…	9,000		2.07	…
Woodford	22.21	…	4,700		2.98	…
Cana Woodford	5.72	…	688		5.20	…
Total Mid-Continent	**59.88**	**…**	**14,388**		**2.45**	**…**
Barnett	43.38	…	4,075	2,383	1.42	…
Barnett Woodford	32.15	…	2,691		3.07	…
Total Southwest	**75.52**	**…**	**6,766**	**2,383**	**1.85**	**…**
Hilliard-Baxter-Mancos	3.77	…	16,416		0.18	…
Lewis	11.63	…	7,506		1.30	…
Williston-Shallow Niobraran*	6.61	…	**NA**		0.45	…
Mancos	21.02	…	6,589		1.00	…
Total Rocky Mountain	**43.03**	…	**30,511**		**0.69**	…
Total Lower 48 U.S.	**750.38**	**…**	**160,413**	**136,081**	**1.02**	**…**

***Cincinnati Arch and Williston-Shallow Niobraran were not assessed in this report.**

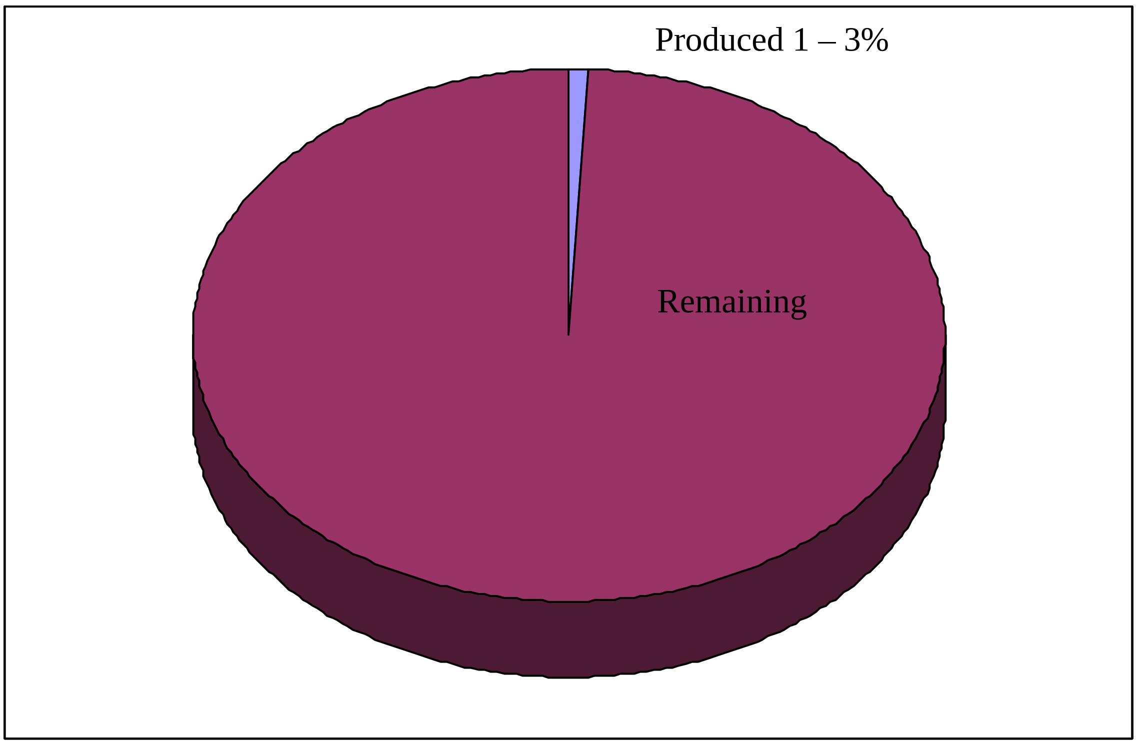
The 750 trillion cubic feet of shale gas resources in the INTEK shale report is a subset of the *AEO2011* onshore lower 48 natural gas shale resource estimate of 862 trillion cubic feet. The AEO2011 includes 35 trillion cubic feet of "proved reserves" reported to the Securities and Exchange Commission (SEC) and the EIA[1], 20 trillion cubic feet of inferred reserves not

[1] Additional information and comparisons of the SEC and EIA reserves can be found in the EIA report "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves, 2009"

included in the INTEK shale report, and 56 trillion cubic feet of undiscovered resources estimated by the USGS. Of that amount, 41.4 trillion cubic feet is located in Southern California and 14.6 trillion cubic feet in the Rocky Mountain region. The play average expected ultimate recoveries (EUR) are between 0.12 billion cubic feet (Bcf) and 3.6 Bcf per well. The largest concentrations of shale gas are contained in the Northeast region which contains the Marcellus Shale and the Gulf Coast region containing the Haynesville Shale.

Figure ii shows the technically recoverable shale gas resource and the fraction which has already been produced. The figure shows that, excluding the Appalachian plays and some of the newly developing plays, between one and three percent has been produced. The size of the remaining resource underscores the importance that shale gas can play in U.S. natural gas production as well as the necessity of this resource review.

Figure ii Shale Gas Technically Recoverable Resources and Cumulative Production[2]



In order to realize this production, substantial drilling is required. As the effective lifespan of the shale gas wells is relatively short, new wells are required to maintain current production levels as well as increase them.

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and a supplemental report "Top 100 Operators: Proved Reserves and Production, Operated vs Owned, 2009". http://www.eia.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html

[2] Due to data availability, the Appalachian plays not included in Figure ii are the Marcellus, Devonian Big Sandy, Devonian Low Thermal Maturity, Devonian Greater Siltstone and Cincinnati Arch.

Shale Oil

In addition to the gas produced in the shale plays, condensate and plant liquids may also be produced. Four shale oil plays were also identified and reviewed during this analysis. As seen in the following Table, the majority of these resources are located in the Monterey/Santos shales currently under development by OXY. The technically recoverable resource for these four plays is approximately 24 Billion barrels of oil (BBO) across nearly 13,000 square miles. The average EUR for the plays is approximately 460 thousand barrels of oil (MBO).

Table ii U.S. Technically Recoverable Shale Oil Resources Summary

Play	Technically Recoverable Resource		Area (sq. miles)		Average EUR	
	Gas (Tcf)	Oil (BBO)	Leased	Unleased	Gas (Bcf/ well)	Oil (MBO/ well)
Eagle Ford	…	3.35	3,323		…	300
Total Gulf Coast	**…**	**3.35**	**3,323**		**…**	**300**
Avalon & Bone Springs	…	1.58	1,313		…	300
Total Southwest	**…**	**1.58**	**1,313**		**…**	**300**
Bakken	…	3.59	6,522		…	550
Total Rocky Mountain	**…**	**3.59**	**6,522**		**…**	**550**
Monterey/Santos	…	15.42	1,752		…	550
Total West Coast	**…**	**15.42**	**1,752**		**…**	**550**
Total Lower 48 U.S.	**…**	**23.94**	**12,910**		**…**	**460**

References

1. Department of Energy, Energy Information Administration. *Annual Energy Outlook 2010.* April 2010.
2. Department of Energy, Energy Information Administration. Modified by INTEK Inc.
3. Congressional Research Services. *Unconventional Gas Shales: Development, Technology, and Policy Issues.* October 2009.
4. NRG & Associates and HPDI Data.

I. Introduction

This document provides a brief description of shale gas and shale oil plays in the United States organized by chapters based on the oil and gas supply module regions. The regions included in this document are the Northeast, Gulf Coast, Mid-Continent, Southwest, Rocky Mountain, and West Coast Region. Each play description includes an estimate of the resource at the well level and across the play, description of key properties, a list of the companies active in the play as well as their activities, a comparison against United States Geological Survey (USGS) estimates, and other information. This information has been collected from publicly available data sources including USGS, the Department of Energy (DOE), individual exploration and development companies, journal articles, and other data sources.

The resource estimates in the following play descriptions were developed using a wide variety of data sources. These sources include institutes such as the USGS, professional associations such as the American Association of Petroleum Geologists (AAPG), commercial databases from the HPDI and Nehring Associates (NRG), integrated oil and gas companies, and service companies. In addition to these public sources of data, proprietary data and insights gleamed from conversations with experts were used to augment the estimates of resource and other parameters. The acreage which is reported includes sections which are currently being produced. The Technically Recoverable Resources (TRR) provided in Table i and in the following play descriptions are a function of the area, the well spacing, and the play average EUR. An effective recovery factor has been applied which reflects (a) a probability factor which takes into account the results from current shale gas activity as an indicator of how much is known or unknown about the shale formation, (b) a recovery factor which takes into account prior experience in how production occurs, on average, given a range of factors including mineralogy and geologic complexity that affect the response of the geologic formation to the application of best practice shale gas recovery technology, and (c) the removal of the resources in the play that have already been produced or added into proved reserves. The EURs presented in this report do not include natural gas plant liquids.

The Northeast Region includes the Marcellus, Devonian Big Sandy, Devonian Low Thermal Maturity, Devonian Greater Siltstone, New Albany and the Antrim shale gas plays.

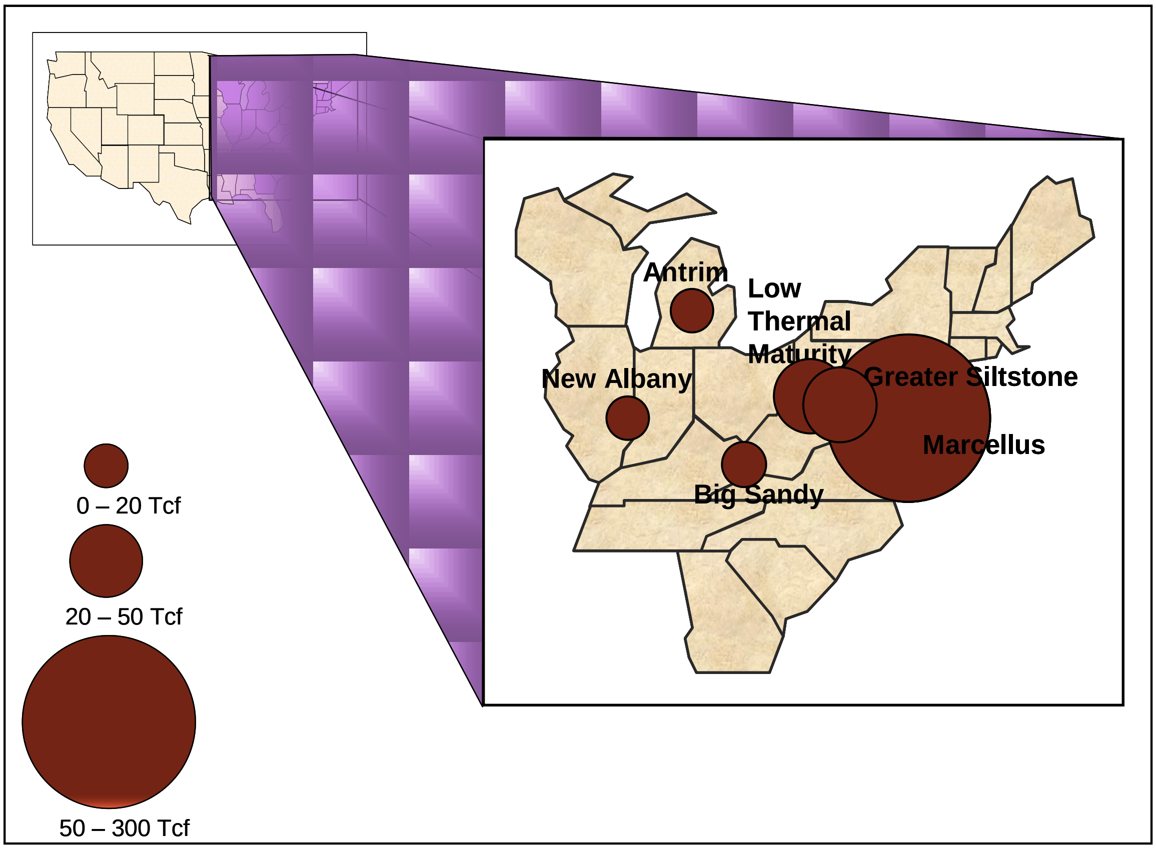
- The Gulf Coast Region includes the Haynesville, Eagle Ford and the Floyd-Neal/Conasauga shale gas and shale oil plays.
- The Mid-Continent Region includes the Fayetteville, Woodford and the Cana Woodford shale gas plays.
- The Southwest Region includes the Barnett, Barnett-Woodford, and the Avalon and Bone Springs shale gas and shale oil plays.
- The Rocky Mountain Region includes the Hilliard-Baxter-Mancos, Lewis, Mancos and the Bakken shale gas and shale oil plays.
- The West Coast Region includes the Monterey/Santos shale oil play.

Introduction

II. Northeast Regional Summary

The Northeast region includes shale gas plays located in the Appalachian, Illinois and Michigan Basins. The Appalachian Basin includes the Marcellus, Devonian Big Sandy, Devonian Low Thermal Maturity, and the Devonian Greater Siltstone shale plays (Figure 1). New Albany is located in the Illinois Basin and the Antrim shale play is located within the Michigan Basin. The shale plays in the Northeast region cover a total estimated area of 229,927 square miles with an average EUR between 0.3 and 2.3 Bcf per well and approximately 472 Tcf of technically recoverable gas.

Figure 1 Northeast Shale Gas and Shale Oil Resources



Northeast Region

A. Marcellus Shale Gas Play

Play Description

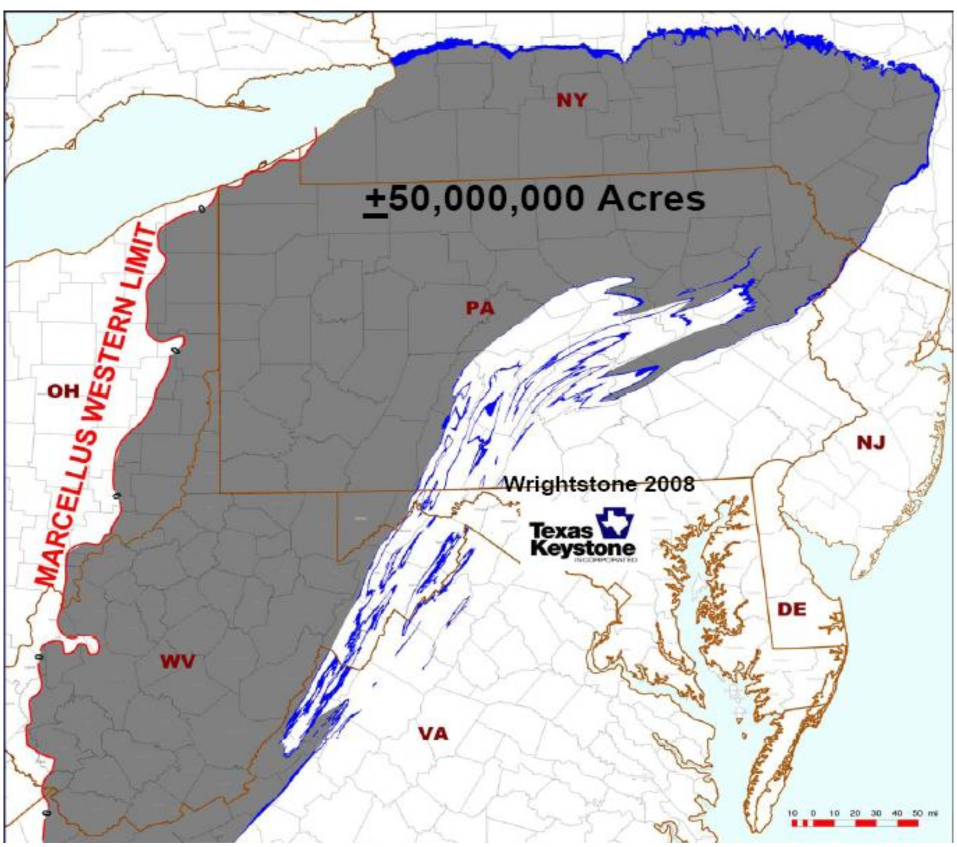
The Marcellus shale gas play is located in the Appalachian Basin across the Eastern Part of the United States. The states which contain the shale, according to the USGS, are provided in Table 1.

Table 1 State Distribution of the Marcellus Shale Play

State	Areal % of Marcellus
Maryland	1.09
New York	20.06
Ohio	18.19
Pennsylvania	35.35
Virginia	3.85
West Virginia	21.33

For purposes of EIA's modeling, the Marcellus was divided into two main units: the Active Area and the Undeveloped Area. The active area, defined using the acreage reportedly under lease by the companies, is primarily located within West Virginia and Pennsylvania. This area is 10,622 square miles. The remainder of the area, 84,271 square miles corresponds to the area which has not been leased by the companies. The areal extent of the Marcellus shale is provided in Figure 2.

Figure 2 Marcellus Shale Play



Resource Estimate

As estimated by the USGS, the Marcellus shale has a total area of 95,000 square miles. The depth of the shale ranges between 4,000 and 8,500 with a thickness between 50 to 200 feet. The average EUR for both the active and undeveloped areas is 2.325 Bcfe per well. The active area, as detailed in Table 2, is 10,622 square miles and has a total TRR of 177.9 Tcf, which is equivalent to 3.5 Bcf per well. At the well level, the overwhelming majority of reported EURs range between 3 and 4 Bcf. Due to a development moratorium in New York, access to resource, lack of current production, and other issues in the undeveloped section of the Marcellus, the number of drilling locations and the total TRR is uncertain. However, the well level EUR has been estimated at 1.15 Bcf.

Table 2 Marcellus Average EUR and Area

	Active	Undeveloped
Area (sq. miles)	10,622	84,271
EUR (Bcfe/ well)	3.5	1.15
Well Spacing (wells/ sq. mile)	8	8
TRR (Tcf)	177.90	232.44

Other average properties were estimated for the Marcellus shale play. These include the depth, thickness, porosity, and total organic content for the shale. The values are provided in Table 3.

Table 3 Average General Properties for the Marcellus Shale Play

Depth (ft)	6,750
Thickness (ft)	125
Porosity (%)	8
Total Organic Content (% wt)	12

Active Companies

In 2008, there were 19 companies holding leases in the Marcellus shale. These companies, along with their net acreage, are provided in Table 4.

Table 4 Marcellus Lease Holders

Company	Net Acreage
Anadarko Petroleum	275,000
Atlas Energy Resources LLC	483,000
Cabot Oil & Gas	332,919
Carrizo Oil & Gas	57,000
Chesapeake	1,200,000
CNX Gas	161,000
Dominion	800,000
Equitable Resources	400,000
EXCO Resources	393,000
Penn-Virginia	15,000
Petroleum Development	35,000
Range Resources	1,400,000
Rex Energy	57,000
Quest energy Partners L.P.	119,000
Southwestern Energy	100,000
Talisman	640,000
Ultra Petroleum	140,100
Unit Corp.	38,000
XTO Energy	152,000

Based upon these lease holdings, the total active area is calculated at 6,798,019 net acres (10,622 square miles).

Well Costs

In 2008, Deutsche Bank reported the average well cost as between $3 and $4 million dollars. This is approximately the level of costs reported in 2010 by the majority of the companies. The highest reported cost is Rex Energy – between $4.5 and $4.7 million dollars.

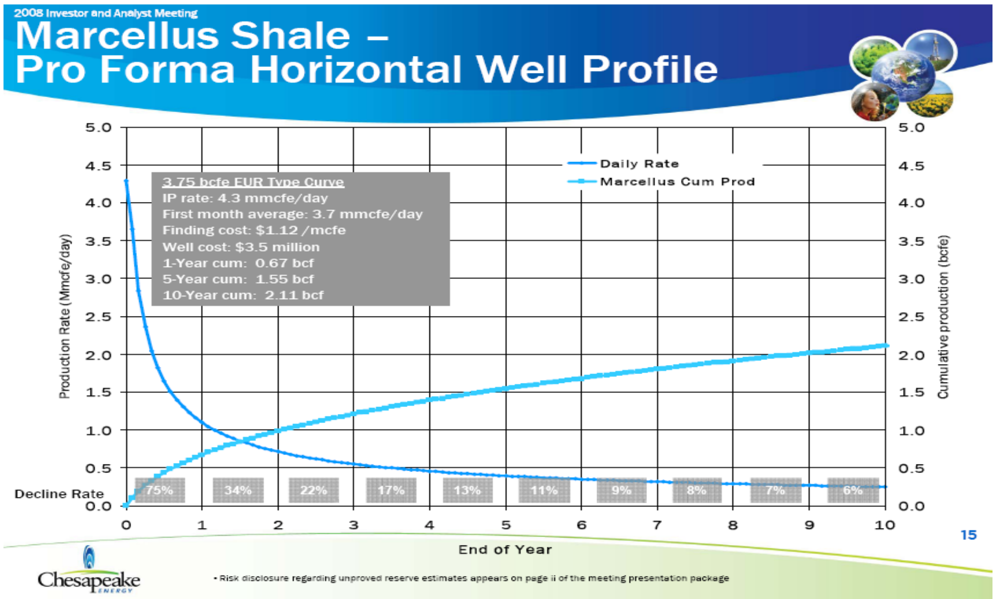
USGS Comparison

In 2002, the USGS conducted an assessment of the Marcellus shale. They estimated that the total undiscovered resource is between 822 and 3,668 Bcf, with a mean of 1,925 Bcf.

Representative Type Curve

Figure 3 provides a representative type curve for a horizontal well in the Marcellus shale. According to Chesapeake Energy, the decline rate is initially 75% and bottoms out at 6% in the later years.

Figure 3 Marcellus Type Curve



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1. USGS. *Assessment of Undiscovered Oil and Gas Resources of the Appalachian Basin Province*. 2002.
2. Deutsche Bank. *From Shale to Shining Shale.* July 2008.
3. Wrightstone Gregory, Texas Keystone, Inc. *Marcellus Shale – Geologic Controls on Production. Presented at the Winter Meeting of the IOGAWV*. February 2009.
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6. XTO Energy. *Barnett vs. Marcellus – A Comparison of Two Shale Gas Giants.* June 2009.
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8. Chesapeake Energy. *Marcellus Shale Overview*. 2008.
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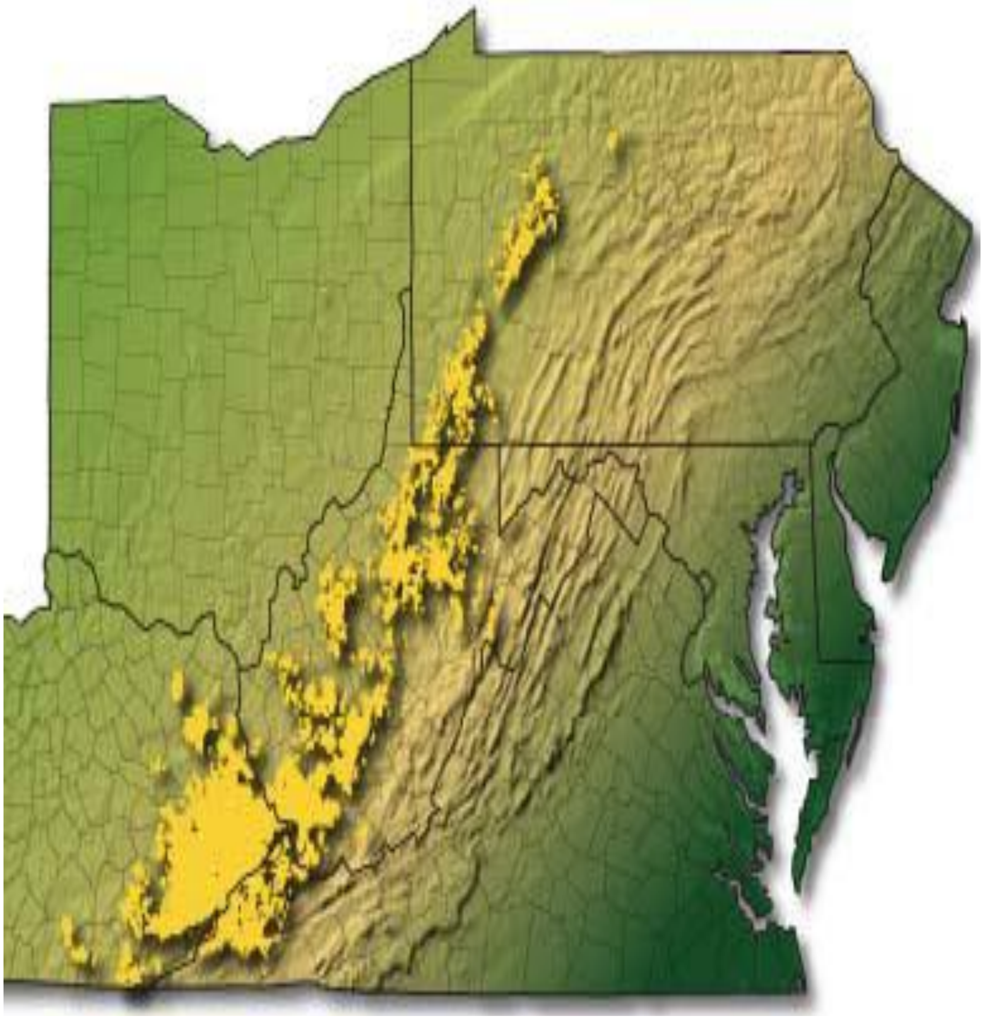
13. Range Resources. *The Marcellus Shale.* 2007.
14. TransEnergy Incorporated. 2008.
15. Phasis Consulting. *US Shale Gas Brief.* September 2008.
16. Baylor, Brandon. *Marcellus Shale Decline Analysis.* 2010.
17. McKinsey & Company. *The Surge of North American Unconventional Gas and Its Impact.* Presented at the Conference on Energy in the USA, Paris. June 2010.

B. Devonian Big Sandy Shale Gas Play

Play Description

The Devonian Big Sandy shale gas play includes the Huron, Cleveland and Rhinestreet formations located within the Appalachian Basin in Kentucky, Virginia and West Virginia. For modeling purposes, the Big Sandy was divided into two main units: the Developed Area and Undeveloped Area. The location of the Big Sandy shale play is provided in Figure 4.

Figure 4 Devonian-Big Sandy Shale Play



Resource Estimate

The USGS estimated a total area for the Big Sandy shale play as 10,669 square miles (6,828,000 acres). The shale play has an average EUR of 0.325 Bcf per well and approximately 7.4 Tcf of technically recoverable gas. Big Sandy has a total active area of approximately 8,675 square miles and an undeveloped area of 1,994 square miles with a well spacing of 80 acres per well. According to Deutsche Bank, Big Sandy ranges from 1,600 to 6,000 feet deep and has a thickness of 50 to 300 feet. These values are provided in Tables 5 and 6.

Table 5 Devonian Big Sandy Average EUR and Area

	Active	Undeveloped
Area (sq. miles)	8,675	1,994
EUR (Bcf/ well)	0.325	0.325
Well Spacing (wells/ sq. mile)	8	8
TRR (Tcf)	6.47	0.92

Other average properties were estimated for the Big Sandy shale play. These include the depth, thickness, porosity, and total organic content for the shale. The values are provided in Table 6.

Table 6 Average General Properties for the Devonian Big Sandy Shale Play

Depth (ft)	3,800
Thickness (ft)	175
Porosity (%)	10
Total Organic Content (% wt)	3.75

Active Companies

In 2008, there were 10 companies holding leases in Big Sandy. These companies, along with their net acreage, as reported by Deutsche Bank, are listed in Table 7.

Table 7 Devonian-Big Sandy Lease Holders

Company	Net Acreage
Cabot Oil & Gas	962,471
Chesapeake Energy	500,000
CNX Gas	193,000
Dominion	300,000
Equitable Resources	2,900,000
EXCO Resources	117,000
GeoMet	52,000
NGAS Resources	275,000
Penn-Virginia	87,500
Range Resources	165,000

Based upon these lease holdings, the total active area is calculated at 5,551,971 net acres (8,675 square miles).

Well Costs

In 2008, Deutsche Bank reported a well cost ranging from $0.5 to $3.0 million dollars and as of 2009, Equitable Resources reports an average well cost of approximately $1.2 million dollars.

USGS Comparison

In 2002, the USGS conducted an assessment of Devonian Big Sandy in the Appalachian Basin. They estimated that the total undiscovered resource is between 3,877 and 9,562 Bcf, with a mean of 6,323 Bcf.

References

1. Deutsche Bank. *From Shale to Shining Shale.* July 2008.
2. USGS. *Assessment of the Undiscovered Oil and Gas Resources of the Appalachian Basin Province.* 2002.
3. USGS. *U.S. Geological Survey Open-File Report 2005-1268*. 2005.
4. Range Resources. *March Company Presentation.* March 2009.
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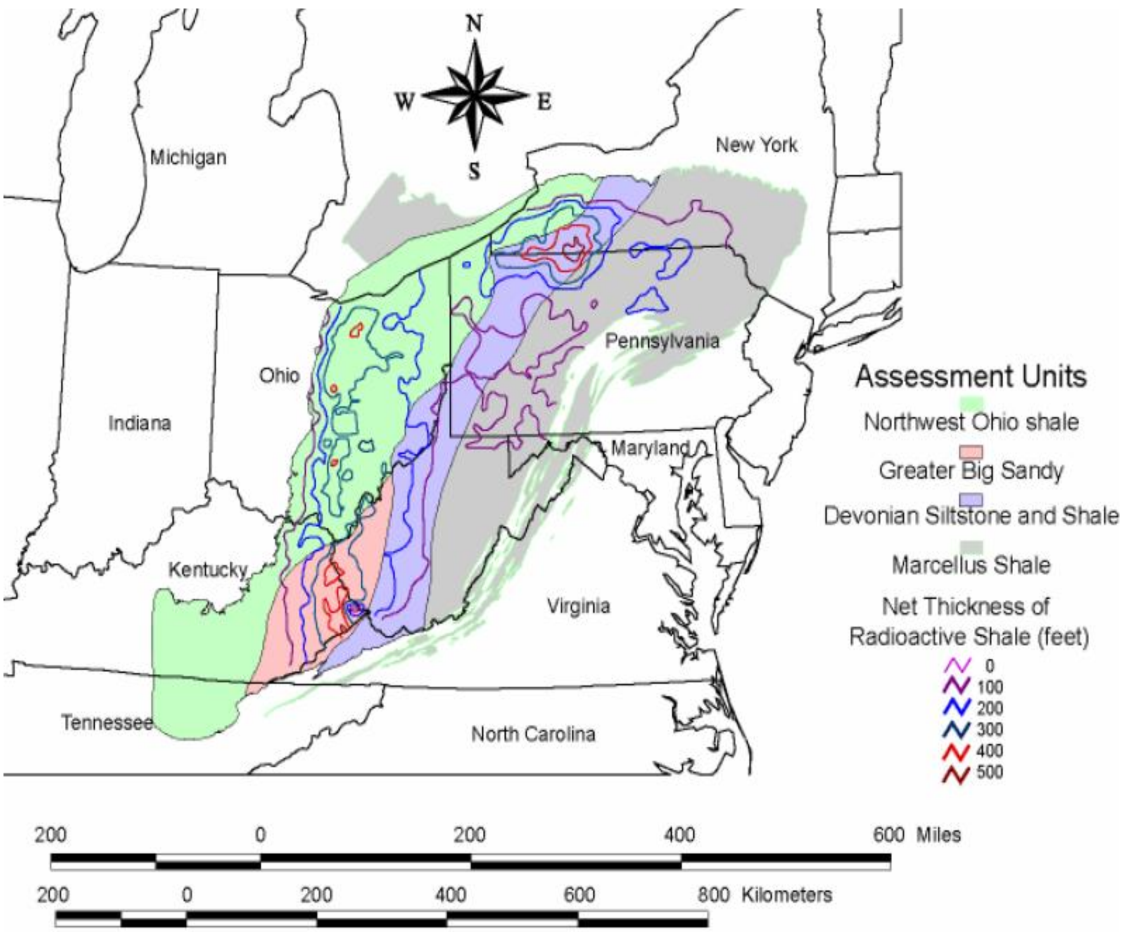
6. Equitable Resources. *Analyst Presentation*. March 2009.

C. Devonian Low Thermal Maturity & Greater Siltstone Shale Gas Plays

Play Description

The Devonian Low Thermal Maturity shale gas play, also know as the Northwestern Ohio shale, is located within the Appalachian Basin in Kentucky, New York, Ohio, Pennsylvania, Tennessee and West Virginia. The location of the Greater Siltstone is also within the Appalachian Basin in New York, Ohio, Pennsylvania, Virginia and West Virginia. The location of the Low Thermal Maturity and Greater Siltstone shale plays are provided in Figure 5.

Figure 5 Devonian Low Thermal Maturity and Greater Siltstone Shale Plays



Resource Estimate

The USGS estimated a total area for the Low Thermal Maturity as 45,844 square miles (29,340,000 acres) and a total area of 22,914 square miles (14,665,000 acres) for the Greater Siltstone shale play. The Devonian Low Thermal Maturity has an average EUR of 0.3 Bcf per well and approximately 13.5 Tcf of technically recoverable gas. The Devonian Greater Siltstone has an average EUR of 0.19 Bcf per well and approximately 8.5 Tcf of technically recoverable gas. These values are provided in Table 8 along with the average EURs and well spacing.

Table 8 Devonian Low Thermal Maturity and Greater Siltstone Average EUR and Area

	Low Thermal Maturity	Greater Siltstone
Area (sq. miles)	45,844	22,914
EUR (Bcf/ well)	0.2942	0.193
Well Spacing (wells/ sq. mile)	7	10.7
TRR (Tcf)	13.53	8.46

Other average properties were estimated for the Low Thermal Maturity and Greater Siltstone shale plays. These include the depth, thickness and porosity for the shale. Total organic content data was not publicly available. The values are provided in Table 9.

Table 9 Average General Properties for the Devonian-Low Thermal Maturity and Greater Siltstone Shale Plays

	Low Thermal Maturity	Greater Siltstone
Depth (ft)	3,000	2,911
Thickness (ft)	371	623
Porosity (%)	7	5.8
Total Organic Content (% wt)	----	----

USGS Comparison

In 2002, the USGS conducted an assessment of the Low Thermal Maturity and Greater Siltstone in the Appalachian Basin. They estimated that the total undiscovered resource for the Low Thermal Maturity is between 1,454 and 4,339 Bcf, with a mean of 2,654 Bcf. The total undiscovered resource for the Greater Siltstone was estimated between 892 Bcf and 1,894 Bcf, with a mean of 1,294 Bcf.

References

1. USGS. *U.S. Geological Survey Open-File Report 2005-1268*. 2005.
2. USGS. *Assessment of the Undiscovered Oil and Gas Resources of the Appalachian Basin Province.* 2002.
3. West Virginia Geological Economic Survey. *Summary Data and Statistics: The Atlas of Major Appalachian Gas Plays*. 1996.

D. New Albany Shale Gas Play

Play Description

The New Albany shale gas play is located in the Illinois Basin in Illinois, Indiana and Kentucky. The location and extent of the New Albany shale is provided in Figure 6.

Figure 6 New Albany Shale Play

Resource Estimate

The total area for the New Albany shale play is approximately 43,500 square miles. The total area includes an active and undeveloped area of the play. Deutsche Bank estimated a total active area of 1,600 square miles. Thus, the remaining area is 41,900 square miles and is characterized as undeveloped area. New Albany has an average EUR of 1.1 Bcf per well and approximately 10.95 Tcf of technically recoverable gas. The depth of the New Albany shale ranges from 1,000 to 4,500 and is 100 to 300 feet thick. Due to the lack of current production and other issues in the undeveloped section of New Albany, the average EUR, well spacing, and total organic content is undetermined. These values are provided in Tables 10 and 11.

Table 10 New Albany Average EUR and Area

	Active	Undeveloped
Area (sq. miles)	1,600	41,900
EUR (Bcf/ well)	1.1	----
Well Spacing (wells/ sq. mile)	8	----
TRR (Tcf)	10.95	

Other properties were estimated for the New Albany shale. These include the depth, thickness, porosity, and total organic content for the shale. The values are provided in Table 11.

Table 11 Average General Properties for the New Albany Shale Play

	Active	Undeveloped
Depth (ft)	2,750	2,750
Thickness (ft)	200	200
Porosity (%)	12	12
Total Organic Content (% wt)	13	----

Active Companies

In 2008, there were 9 companies holding leases in the New Albany shale play. These companies, along with their net acreage, as reported by Deutsche Bank, are listed in Table 12.

Table 12 New Albany Lease Holders

Company	Net Acreage
BreitBurn Energy Partners	168,430
Carrizo Oil & Gas	22,000
CNX Gas	356,000
Continental Resources	44,000
El Paso	122,000
Forest Oil	31,900
NGAS Resources	8,750
Noble Energy	179,000
Rex Energy	92,000

Based upon these lease holdings, the total active area is calculated at 1,024,080 net acres (1,600 square miles).

Well Costs

According to Deutsche Bank, New Albany has a well cost ranging from $0.8 to $1.0 million dollars for the developed area. Due to a lack of drilling activity and harsh terrain in the undeveloped area, well costs in this region of the shale are undetermined.

USGS Comparison

In 2007, the USGS completed an assessment of the Illinois Basin. As part of the assessment, they estimated the undiscovered resource for the Devonian to Mississippian New Albany continuous gas. They estimated resources between 1.3 and 8.1 Tcf with a mean undiscovered resource of 3.8 Tcf.

References

1. U.S. Department of Energy. *Modern Shale Gas Development in the United States: A Primer*. April 2009.
2. Deutsche Bank. *From Shale to Shining Shale.* July 2008.
3. USGS. *Assessment of the Undiscovered Natural Gas Resources of the Illinois Basin.* August 2010.
4. Discovery Group Inc. *2007 New Albany Shale Update.* June 2007.
5. Sundance Energy. *Annual General Meeting.* November 2006.
6. Gas Technology Institute. *New Albany Shale Project – Project Update. Presented at Mid-Continent Gas Shale Forum and RPSEA Member Meeting*. June 2009.
7. Phasis Consulting. *US Shale Gas Brief.* September 2008.
8. Forest Oil Corporation. *In the Zone- 2008 Analyst Conference.* April 2008.
9. Forest Oil Corporation. *Analyst Conference*. March 2006.
10. Marsh Operating Company. *Unconventional Gas Plays SPEE.* December 2007.
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12. GTI, RPSEA, and Restech. *Spring Topical Conference 2009- Philadelphia Shale Evaluation. New Albany Example- RPSEA/ GTI Project*. 2009.
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New Albany

E. Antrim Shale Gas Play

Play Description

The Antrim shale gas play is located in the Michigan Basin in the northern part of Michigan State. According to Red Fork Energy, the Antrim shale is the 13th largest natural gas producer in the United States. The location of the Antrim shale is provided in Figure 7.

Figure 7 Antrim Shale Play

Resource Estimate

The total area of the Antrim shale play is approximately 12,000 square miles as shown in Table 13. The total area includes the developed and undeveloped area of the play. Based upon the active area reported by Deutsche Bank, the developed area is approximately 527 square miles. Thus, the remaining area is 11,743 square miles as undeveloped area. Due to the large difference in areas of the developed and undeveloped sections, Antrim shale is being modeled as a single unit. The shale gas play has an average EUR of 0.28 Bcf per well and approximately 19.9 Tcf of technically recoverable gas. Antrim ranges from 600 to 2,200 feet deep and is 70 to 120 feet think.

Table 13 Average Antrim EUR and Area

	Active
Area (sq. miles)	12,000
EUR (Bcf/ well)	0.28
Well Spacing (wells/ sq. mile)	7
TRR (Tcf)	19.93

Other average properties were estimated for the Antrim shale play. These include the depth, thickness, porosity, and total organic content for the shale. The values are provided in Table 14.

Table 14 Average General Properties for the Antrim Shale Play

Depth (ft)	1,400
Thickness (ft)	95
Porosity (%)	9
Total Organic Content (% wt)	11

Active Companies

In 2008, there were 4 companies holding leases in the Antrim shale play. These companies, along with their net acreage, as reported by Deutsche Bank, are listed in Table 15.

Table 15 Antrim Lease Holders

Company	Net Acreage
Atlas Energy Resources LLC	53,000
BreitBurn Energy Partners	256,438
HighMount E&P LLC	1,778
Whiting Petroleum	25,869

Based upon these lease holdings, the total active area is calculated at 337,085 net acres (527 square miles).

Well Costs

In 2008, Deutsche Bank estimated an average well cost for the Antrim shale play ranging from $0.3 to $0.5 million dollars.

Current Activities

Antrim shale activity began in 1980 with 9,000 completed wells as of 2008.

USGS Comparison

In 2004, USGS conducted an assessment of undiscovered oil and gas resources of the U.S. Portion of the Michigan Basin. As part of the assessment, they evaluated the Devonian Antrim continuous gas. Their estimate ranged from 5,864 Bcf to 9,669 Bcf with a mean of 7,475 Bcf.

Reference

1. Red Fork Energy. *Red Fork Energy's Large Shale Gas Discovery in Oklahoma-Investor Presentation*. May 2010.
2. U.S. Department of Energy. *Modern Shale Gas Development in the United States: A Primer*. April 2009.

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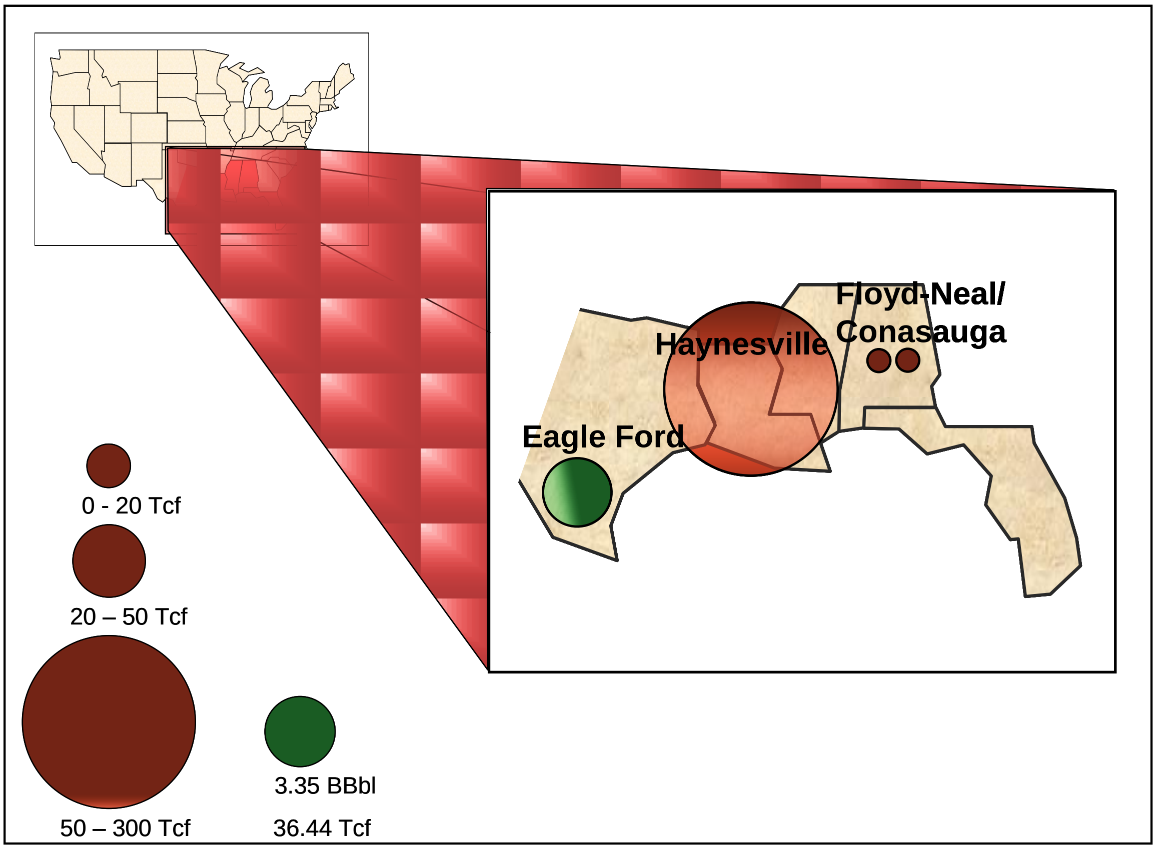
9. Milind Deo from University of Utah. *Shale Gas- Promise and Current Status*. 2008.
10. Phasis Consulting. *US Shale Gas Brief.* September 2008.
11. Novas Consulting Oil & Gas Consultancy. *US Shale Gas What's Going On*. April 2010.

III. Gulf Coast Regional Summary

The Gulf Coast region includes the Haynesville, Eagle Ford and the Floyd-Neal/Conasauga shale gas and shale oil plays. The Haynesville shale play is located in Texas and Louisiana, Eagle Ford is located in the Texas Maverick Basin and Floyd-Neal/Conasauga lies in the Black Warrior Basin. The reviewed plays have a combined area of 14,752 square miles with an average EUR between 0.9 and 5.0 Bcf per well and 300 MBO per well. The reviewed plays contain approximately 99.99 Tcf of technically recoverable gas and 3.35 BBO of technically recoverable oil.

Figure 8 Gulf Coast Shale Gas and Shale Oil Resources



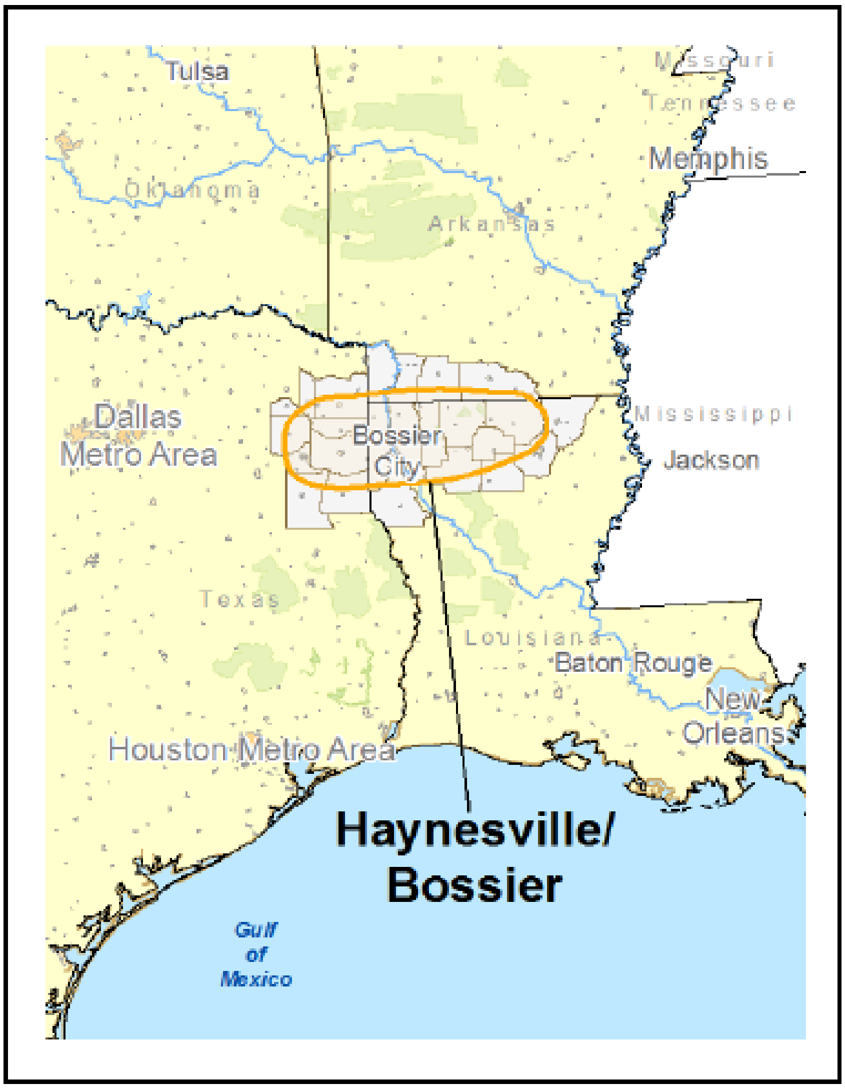
Gulf Coat Region

A. Haynesville Shale Gas Play

Play Description

The Haynesville shale gas play, also known as the Haynesville/Bossier shale play, is located in East Texas and Western Louisiana. In 2007, high shale gas well production rates suggested that the Haynesville might have significant gas reserves. The location of the play is provided in Figure 9.

Figure 9 The Haynesville Shale Play



Resource Estimate

The Haynesville shale has a total area of approximately 9,000 square miles and an estimated technically recoverable resource of 74.7 Tcf. The average EUR per well is estimated to be 3.6 Bcf. The depth of the shale ranges between 10,500 and 13,500 feet with a thickness of 200 to 300 feet. The Haynesville was divided into two zones: active and undeveloped. The active area corresponds with the acreage that is currently held by the companies and might be under development. The undeveloped area represents the acreage that is not currently held by companies.

The active area, as detailed in Table 16, is 3,574 square miles and has a TRR of 53.3 Tcf, which is equivalent to 6.5 Bcf per well. At the well level, the reported EURs range between 4 and 10 Bcf. The TRR for the undeveloped area is 19.41 Tcf or 1.5 Bcf per well.

Table 16 Haynesville Average EUR and Area

	Active	Undeveloped
Area (sq. miles)	3,574	5,426
EUR (Bcf/ well)	6.5	1.5
Well Spacing (wells/ sq. mile)	8	8
TRR (Tcf)	53.30	19.41

Other average properties were estimated for the Haynesville Shale. These include the depth, thickness, porosity, and total organic content for the shale. The values are provided in Table 17.

Table 17 Average General Properties for the Haynesville Shale Play

Depth (ft)	12,000
Thickness (ft)	250
Porosity (%)	8.5
Total Organic Content (% wt)	2.25

Active Companies

In 2008, there were 24 companies holding leases in the Haynesville Shale. These companies, along with their net acreage, are listed in Table 18.

Table 18 Haynesville Lease Holders

Company	Net Acreage
Anadarko Petroleum	60,000
Berry Petroleum	4,508
Cabot Oil & Gas	50,000
Chesapeake	440,000
Comstock	53,000
Cubic Energy	6,326
Devon Energy	200,000
El Paso	27,000
Encana Corp.	325,000
Encore Acquisition	6,000
EOG Resources	150,000
EXCO Resources	107,000
Forest Oil	90,000
GMX Resources	27,500
Goodrich Petroleum	60,500
Noble Energy	18,000
Penn-Virginia	54,000

Company	Net Acreage
Petrohawk	275,000
Plains Exploration & Production	110,000
Questar	29,500
SandRidge	32,739
St. Mary Land & Exploration	50,000
Unit Corp.	11,506
XTO Energy	100,000

Based upon these lease holdings, the total active area is calculated at 2,287,579 net acres (3,574 square miles).

Well Costs

In 2008, Deutsche Bank reported the average well cost as between $6 and $7 million dollars. In 2010, the cost has increased to at least $7 million dollars. The highest cost reported by a company is between $9.5 and $10 million dollars including at least $2 million for stimulation. Both Petrohawk and Encana report costs averaging $9 million per well.

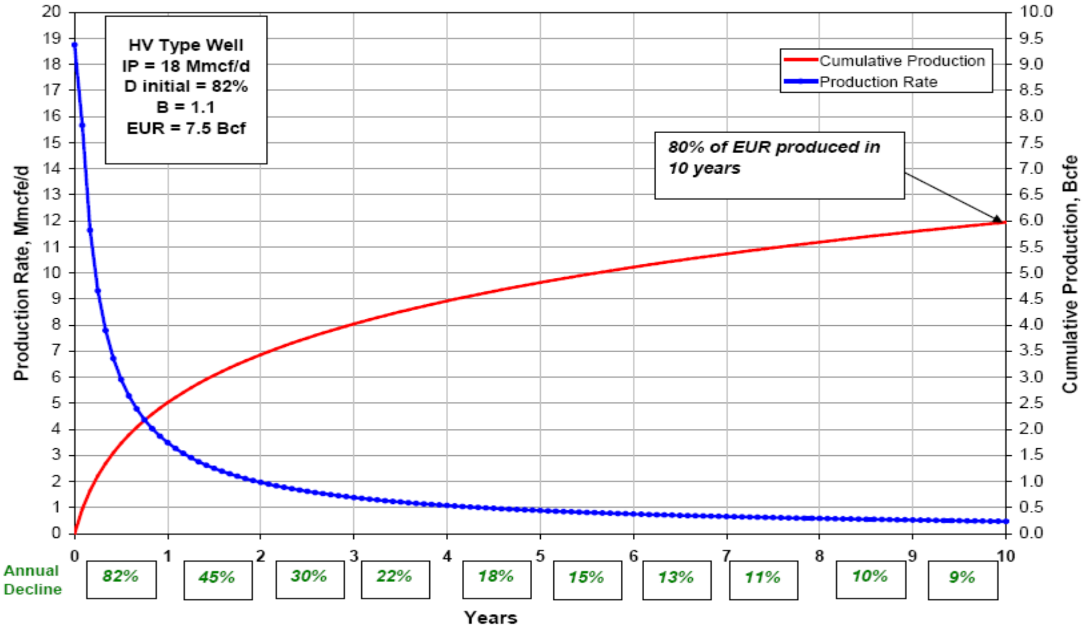
Current Activities

There is significant current drilling activity in the Haynesville. In August of this year, Plains Exploration and Production reported that there were 48 rigs currently active in the play. They further stated that 31 of these were operated by Chesapeake. This report is consistent with statements reported by both Chesapeake and Petrohawk.

Representative Type Curve

Figure 10 provides a representative type curve for a Haynesville well. According to Petrohawk, the well produces 80% of the EUR within the first ten years.

Figure 10 Haynesville Type Curve



USGS Comparison

This play has not been evaluated by USGS.

References

1. U.S. Department of Energy. *Modern Shale Gas Development in the United States: A Primer.* April 2009.
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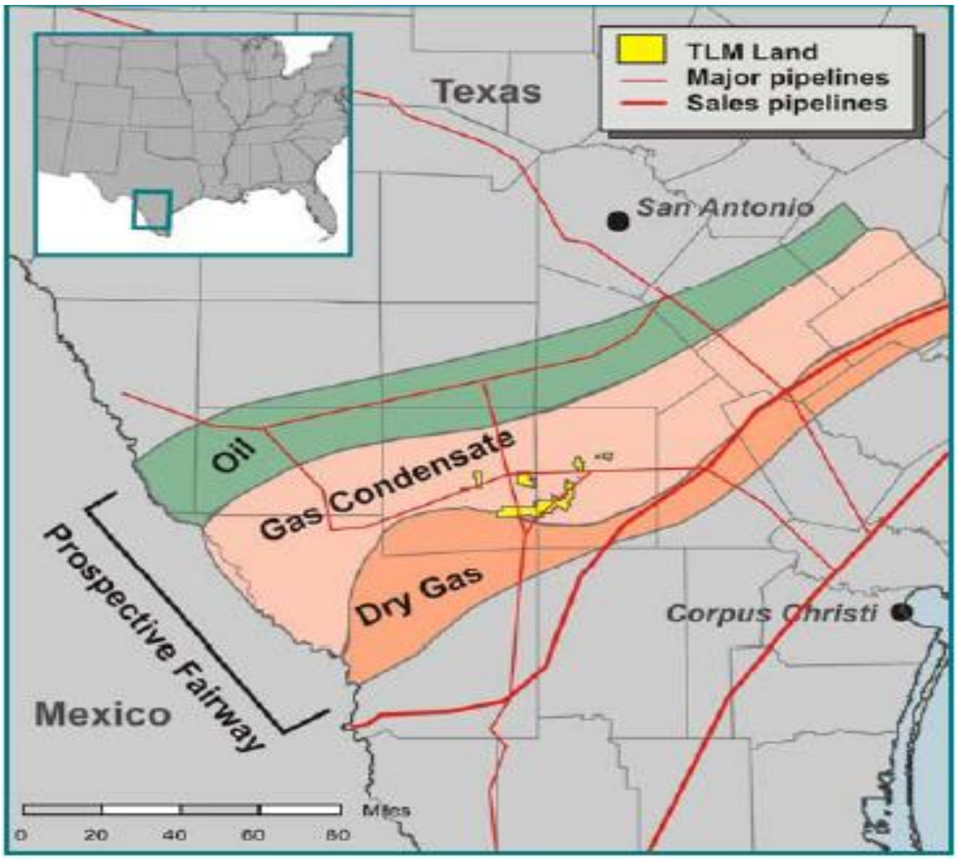
9. ALL Consulting. *Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs.* Presented at the International Petroleum & BioFuels Environmental Conference, Albuquerque, New Mexico. November 2008.
10. Chesapeake Energy. *August 2010 Investor Presentation.* August 2010.
11. Comstock Resources. August 2010.

B. Eagle Ford Shale Gas & Oil Play

Play Description

The Eagle Ford shale gas and oil play is located within the Texas Maverick Basin. The play contains a high liquid component. This has led to the definition of three zones: an oil zone, a condensate zone, and a dry gas zone. The play and the delimitation of the three zones are provided in the following figure.

Figure 11 Eagle Ford Shale Play



The Eagle Ford shale was first discovered by Petrohawk in 2008. The initial well was located in the Hawkville field in LaSalle County, Texas. According to the Railroad Commission of Texas, as of September 2010, there are 162 completed wells in the Eagle Ford as well as 690 well permits.

Resource Estimate

The area for Eagle Ford was calculated using maps and other data reported by the companies who are currently leasing acres with the Eagle Ford shale play. The area of the dry gas zone is estimated at 200 square miles. The same process was done for the oil and condensate zone using the sum of the area for each company. The area of the condensate zone was estimated at 890 square miles and the area for the oil zone is estimated at 2,233 square miles. Eagle Ford has an average EUR of 5.0 Bcf per well and 300 MBO per well. The shale gas and shale oil play has approximately 20.81 Tcf of technically recoverable gas and 3.35 Bbbl of technically recoverable oil.

According to Talisman Energy and Rosetta Resources, 4 Bcf per well was reported as a minimum value for the average EUR, and Petrohawk Energy and Murphy Oil Corporation reported a maximum value of 6 Bcf. An average EUR range of 150 to 750 MBO per well was estimated by Petrohawk Energy as well. The average EUR obtained for the oil zone is 300 MBO, the condensate zone has an average EUR of 4.5 Bcf and the dry gas zone has approximately 5.5 Bcf EUR. The average well spacing ranges from 4 to 8 wells per square mile, with dry gas zone as the lowest, condensate zone the highest and the oil zone with a well spacing of 5 wells per square mile. The TRR for the oil zone is 3.35 BBO while the dry gas and condensate zones have EURs of 4.4 and 16.4 Tcf respectively. The total TRR for the play is 20.8 Tcf of gas and 3.35 BBO of liquids. These values are provided in Table 19.

Table 19 Eagle Ford Average EUR and Areas

	Dry Gas Zone	Condensate Zone	Oil Zone
Area (sq. miles)	200	890	2,233
EUR (Bcf/ well)	5.5	4.5	
EUR (MBO/ well)			300
Well Spacing (wells/ sq. mile)	4	8	5
TRR (BBO)			3.35
TRR (Tcf)	4.38	16.43	

Other average properties were estimated for the Eagle Ford shale play. These include the depth, thickness, porosity, and total organic content for the shale. The values are provided in Table 20.

Table 20 Average General Properties for the Eagle Ford Shale Play

Depth (ft)	7,000
Thickness (ft)	200
Porosity (%)	9
Total Organic Content (% wt)	4.25

Active Companies

There are more than 11 companies currently holding leases in the Eagle Ford shale play. These companies, along with their net acreage, are listed in Tables 21 through 23 for each of the 3 Eagle Ford shale zones.

Table 21 Eagle Ford Dry Gas Zone Lease Holders

Company	Net Acreage
EOG Resources	49,000
Swift Energy	78,000

Table 22 Eagle Ford Condensate Zone Lease Holders

Company	Net Acreage
Comstock	18,000
EOG Resources	26,000
Murphy Oil Corporation	100,000
Petrohawk Energy Corporation	270,000
Pioneer Natural Resources	89,000
Rosetta Resources	29,500
Talisman	37,000

Table 23 Eagle Ford Oil Zone Lease Holders

Company	Net Acreage
Anadarko	260,000
EOG Resources	505,000
Goodrich Petroleum Corporation	35,000
Murphy Oil Corporation	100,000
Petrohawk Energy Corporation	87,000
TXCO Resources	442,000

In 2010, these companies have leased a total of 2,125,500 net acres (3,321 square miles).

Future Development

Since Eagle Ford is a developing play, there is minimal information available on the future drilling activity for the companies currently holding leases within the shale. One of the companies to discuss their future development is Pioneer Natural Resources, who plans to increase drilling activity to 6 – 7 rigs in year 2010, 10 rigs by 2011 and by 2012 they plan to be operating 14 rigs in Eagle Ford.

Drilling Cost

According to Petrohawk Energy the average well cost ranges from 4.0 to 6.5 million dollars per horizontal well.

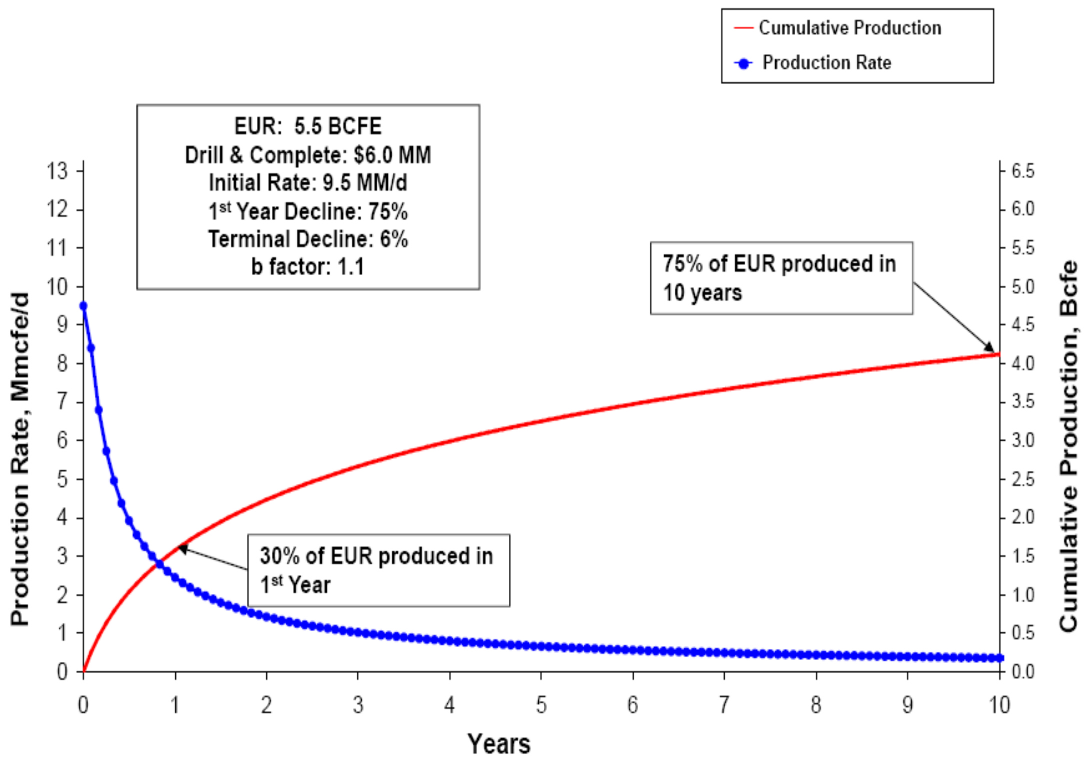
USGS Comparison

This play has not been evaluated by USGS.

Representative Type Curve

Figure 12 provides a representative type curve for an Eagle Ford well. This curve was developed by Petrohawk for the Hawkville Field within the condensate zone of the play. According to Petrohawk, the well will produce 30 percent of the EUR in the first year, and 75% within the first ten years.

Figure 12 Eagle Ford Type Curve



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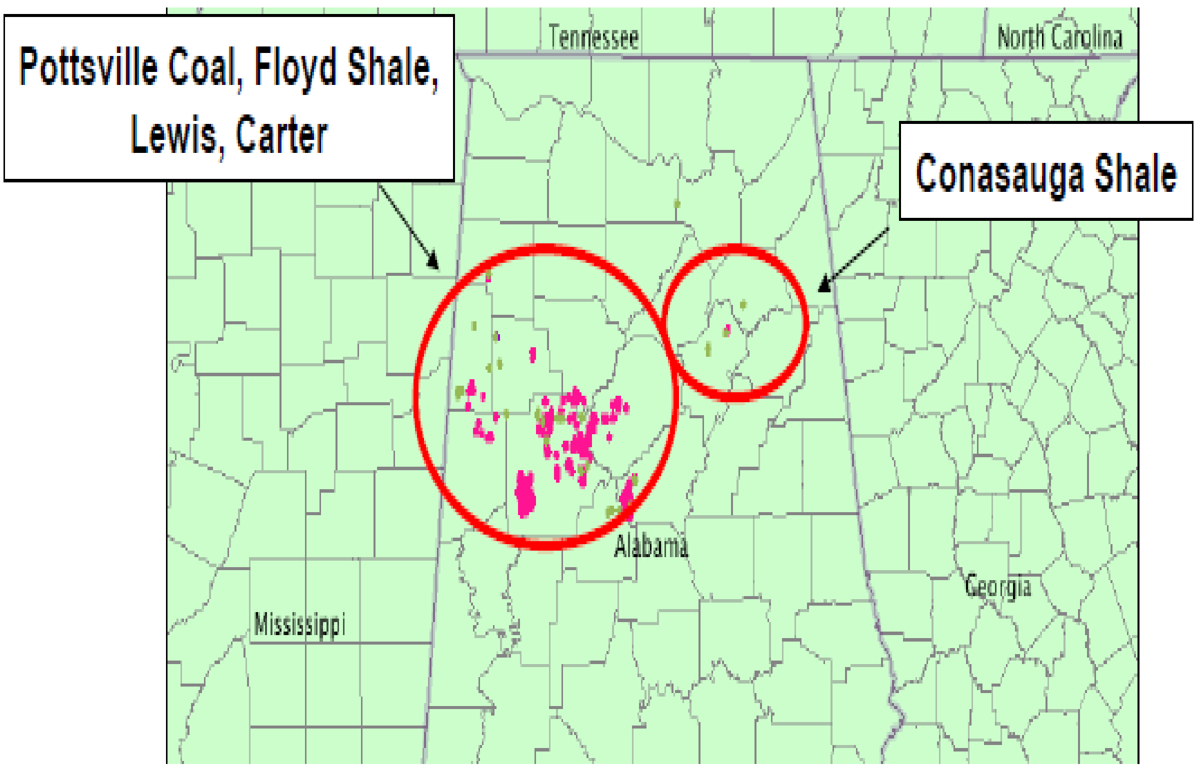
15. Deutsche Bank. *From Shale to Shining Shale.* July 2008.

C. Floyd-Neal/Conasauga Shale Gas Play

Play Description

The Floyd-Neal/Conasauga shale gas play is located within Alabama and Mississippi in the Black Warrior Basin. Due to the lack of data published on the individual shales, the Floyd-Neal and Conasauga were combined into a single play for evaluation purposes. The location and area is proved in Figure 13.

Figure 13 Floyd-Neal/Conasauga Shale Play



Resource Estimate

According to Deutsche Bank, the Floyd-Neal/Conasauga shale contains approximately 2,429 square miles of combined active net acres with an average EUR of about 0.9 Bcf per well and 4.37 Tcf of technically recoverable gas. The shale ranges from 6,000 to 10,000 feet deep and 80 to 180 feet thick with a well spacing of 2 well per square mile (320 acres per well). These values are provided in Tables 24 and 25.

Table 24 Floyd-Neal/Conasauga Average EUR and Area

	Active
Area (sq. miles)	2,429
EUR (Bcf/ well)	0.9
Well Spacing (wells/ sq. mile)	2
TRR (Tcf)	4.37

Other average properties estimated for the Floyd-Neal/Conasauga are provided in Table 23. These include the depth, thickness, porosity, and total organic content for the shale.

Table 25 Average General Properties for the Floyd-Neal/Conasauga Shale Play

Depth (ft)	8,000
Thickness (ft)	130
Porosity (%)	1.6
Total Organic Content (% wt)	1.8

Active Companies

The active companies, along with their net acreage, are provided in Table 26.

Table 26 Floyd-Neal/Conasauga Lease Holders

Company	Net Acreage
Anadarko Petroleum	250,000
Carrizo Oil & Gas	138,000
Chesapeake Energy	287,500
Edge Petroleum	13,563
Energen	287,500
HighMount E&P LLC	328,038
Murphy Oil	200,000
Range Resources	50,000

These companies have leased a total of 1,554,601 net acres (2,429 square miles).

Current Activities

Since the Floyd-Neal/Conasauga shale play is a new developing play, there is minimal information published for the future drilling activity for the companies who are currently holding leases within the shale.

Well Costs

The average well cost for the Floyd-Neal/Conasauga shale is $3.0 million dollars as reported by Deutsche Bank.

USGS Comparison

This play has not been evaluated by USGS.

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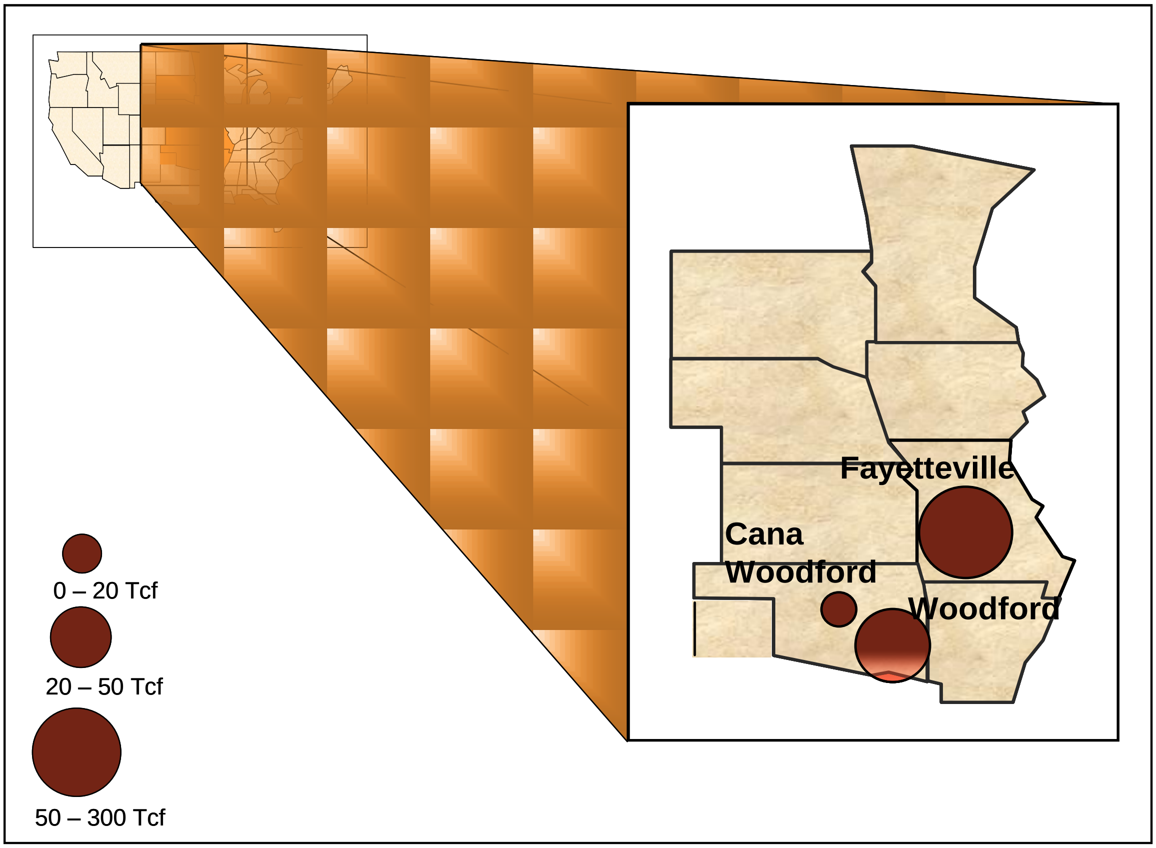
IV. Mid-Continent Regional Summary

The mid-continent region includes shale gas plays located in the Arkoma, Ardmore and Anadarko Basins. Located within theses basins are the Fayetteville, Woodford and Cana Woodford shale plays (Figure 14). The total area of the reviewed plays is estimated at 14,388 square miles with an average EUR between 1.7 and 2.5 Bcf and approximately 59.9 Tcf of technically recoverable gas.

Figure 14 Mid-Continent Shale Gas and Shale Oil Resources



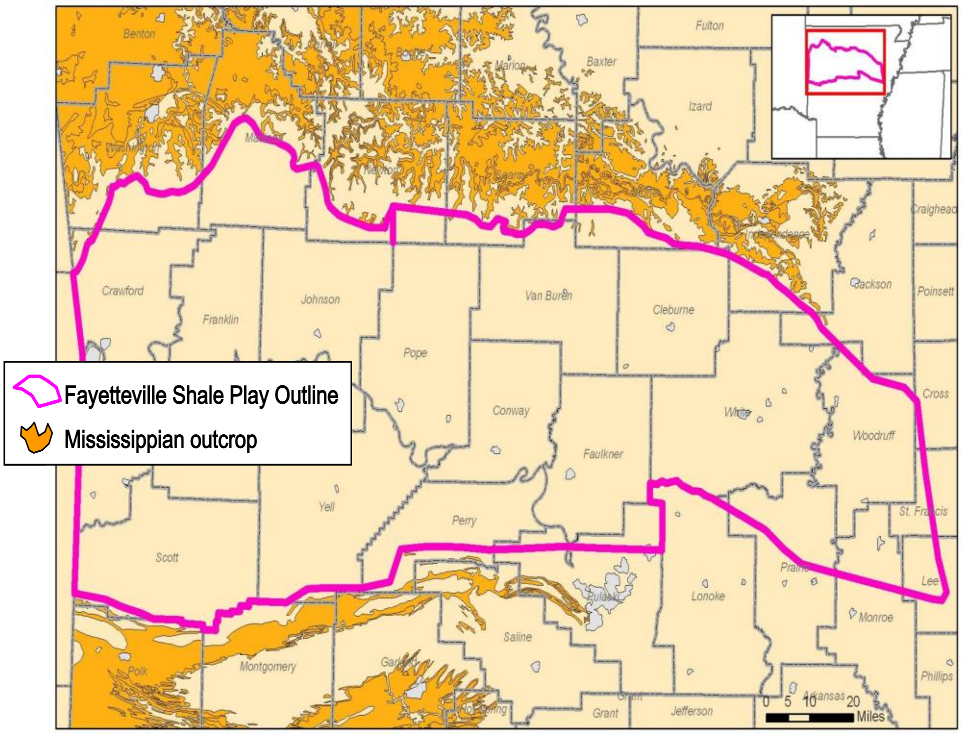
Mid-Continent Region

A. Fayetteville Shale Gas Play

Play Description

The Fayetteville shale gas play is located within the Arkoma Basin in Arkansas. Fayetteville is divided into two main units, Central and Western based on the location of the shale. Fayetteville Central extends from the Arkansas-Oklahoma border to the East of Johnson, Logan and Yell counties. Figure 15 shows the location and area of Fayetteville Central.

Figure 15 Fayetteville Shale Play



Resource Estimate

Based on the U.S. Department of Energy, the total area for the Fayetteville shale play, including Central and Western Fayetteville, is 9,000 square miles. Fayetteville Central is 4,000 square miles and the remaining shale, Fayetteville Western, is approximately 5,000 square miles. The shale gas play has an average EUR of 1.7 Bcf per well and approximately 31.96 Tcf of technically recoverable gas. The shale ranges from 1,000 to 7,000 feet deep and 20 to 200 feet thick. These values are summarized in Tables 27 and 28.

Table 27 Fayetteville Average EUR and Area

	Western	Central
Area (sq. miles)	5,000	4,000
EUR (Bcf/ well)	1.15	2.25
Well Spacing (wells/ sq. mile)	8	8
TRR (Tcf)	4.64	27.32

Other average properties estimated for the Fayetteville shale play are provided in Table 28. These include the depth, thickness, porosity, and total organic content for the shale.

Table 28 Average General Properties for the Fayetteville Shale Play

	Central/ Western
Depth (ft)	4,000
Thickness (ft)	110
Porosity (%)	5
Total Organic Content (% wt)	6.9

Active Companies

In 2008, there were 9 companies holding leases within the Fayetteville shale play. These companies, along with their net acreage, as reported by Deutsche Bank, are listed in Table 29.

Table 29 Fayetteville Lease Holders

Company	Net Acreage
Carrizo Oil and Gas	23,900
Chesapeake	585,000
Edge Petroleum	4,692
Penn-Virginia	14,500
PetroHawk	155,000
PetroQuest	18,000
Southwestern Energy	851,069
Storm Cat Energy	18,265
XTO Energy	300,000

These companies have leased a total of 1,970,426 net acres (3,079 square miles).

In 2010, XTO Energy reported that they increased their Fayetteville acreage to 380,000 net acres. Carrizo Oil and Gas reported 26,000 net acres and Southwestern Energy has a total of 888,695 net acres in 2010.

Well Costs

According to Southwestern Energy, the average well cost completed for 2009 was $2.9 million dollars. This is within the range of $1.75 to $3.05 million dollars as reported by Deutsche Bank.

Current Activities

Southwestern Energy drilled and completed 249 wells within the first six months of 2010. They plan on participating in 650 to 680 wells by the end of the year and operate on 475 to 500 wells. Currently, Chesapeake Energy is operating about 8 rigs and plans to have about 10 rigs in 2010 to drill about 85 net well.

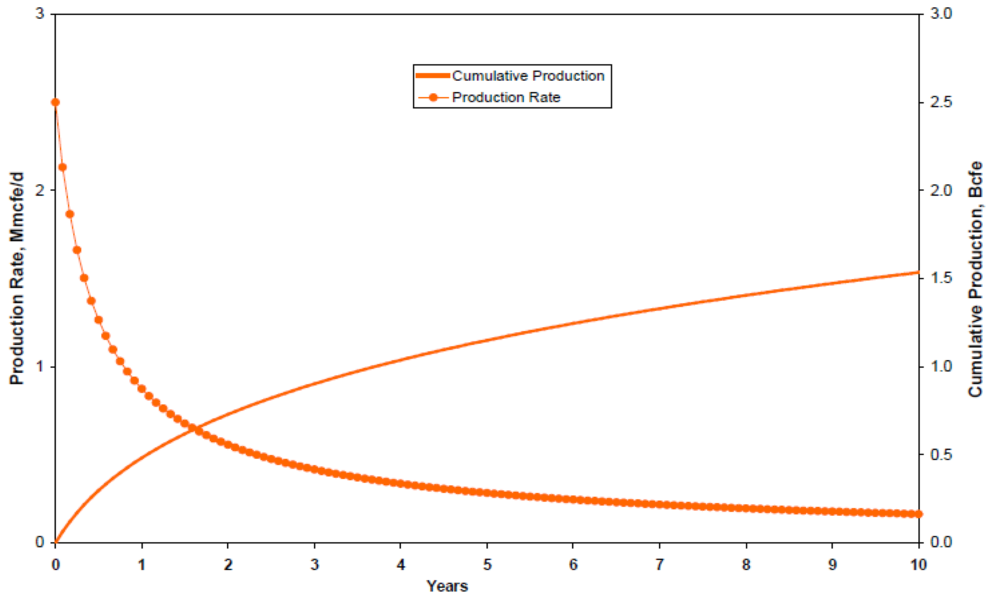
USGS Comparison

In 2010, the USGS conducted an assessment for the Fayetteville Shale Gas-Western Arkansas Basin Margin. They estimated that the total undiscovered resource is between 2,260 and 6,865 Bcf, with a mean of 4,170 Bcf.

Representative Type Curve

Figure 16 provides a representative type curve for a Fayetteville well. According to Petrohawk, this 2.2 Bcfe Fayetteville type curve show the cumulative production and production rate for the play.

Figure 16 Fayetteville Type Curve



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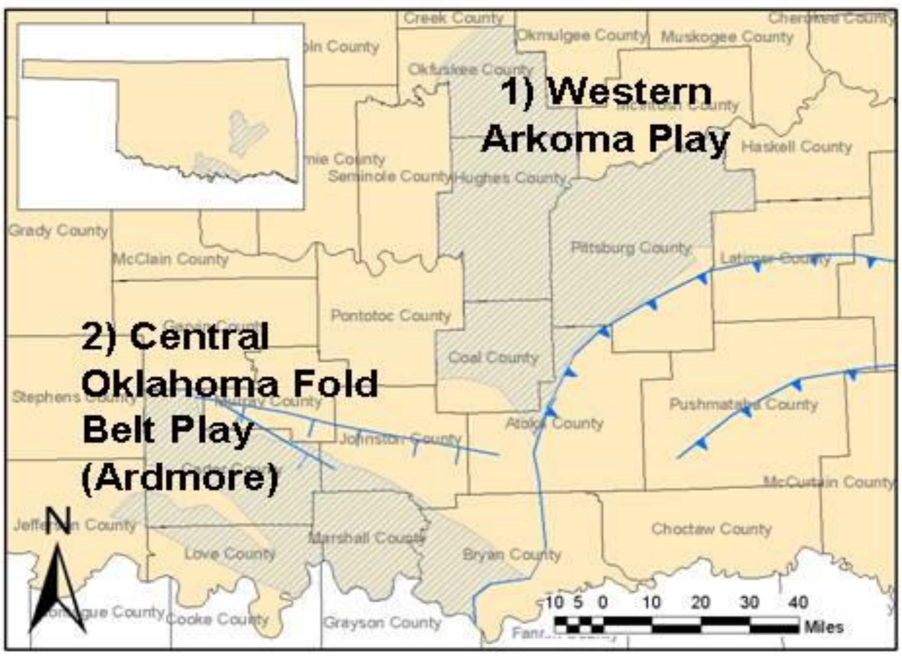
Fayetteville

B. Woodford Shale Gas Play

Play Description

The Woodford shale gas play is divided into two sections based on the location of the shale in Oklahoma. The Woodford Central is located in the Ardmore Basin and Woodford Western is located in the Arkoma Basin. The locations of the Woodford shales are provided in Figure 17.

Figure 17 Woodford Shale Play



Resource Estimate

Advanced Resources International estimated a total area for the Woodford Shales as 2,900 square miles in the Arkoma Basin and 1,800 square miles in the Ardmore Basin, both containing a well spacing of 160 acres per square mile. The shale gas play has an average EUR of 2.5 Bcf per well and approximately 22.2 Tcf of technically recoverable gas for both the Western and Central Woodford. Within the Arkoma Basin, the Woodford Western ranges from 6,000 to 13,000 feet deep with a thickness of 150 feet and a EUR of 4.0 Bcf per well. The Woodford Central has a depth of 5,000 feet with a EUR of 1.0 Bcf per well. These average values are provided in Tables 30 and 31.

Table 30 Woodford Average EUR and Area

	Western	Central
Area (sq. miles)	2,900	1,800
EUR (Bcf/ well)	4.0	1.0
Well Spacing (wells/ sq. mile)	4	4
TRR (Tcf)	19.26	2.95

Other average properties were estimated for the Woodford shale play. These include the depth, thickness, porosity, and total organic content for the shale. The values are provided in Table 31.

Table 31 Average General Properties for the Woodford Shale Play

	Western	Central
Depth (ft)	9,500	5,000
Thickness (ft)	150	250
Porosity (%)	7	6
Total Organic Content (% wt)	6.5	4

Active Companies

In 2008, there were 13 companies holding leases within Woodford. These companies, along with their net acreage, as reported by Deutsche Bank, are listed in Table 32.

Table 32 Woodford Lease Holders in the Arkoma and Ardmore Basins

Company	Net Acreage
Chesapeake Energy	85,000
Cimarex	25,000
Continental Resources	45,000
Devon Energy	54,000
Linn Energy	46,000
Newfield Exploration	165,000
Penn-Virginia	40,000
Petroquest	39,500
Range Resources	13,000
St. Mary Land & Exploration	40,000
Williams Cos.	90,000
Unit Corporation	18,100
XTO Energy	160,000

These companies have leased a total of 820,600 net acres (1,282 square miles)

Well Costs

In 2007, Marsh Operating Company estimated that well costs for the Woodford shale in the Arkoma Basin range from $6 to $7 million dollars and in 2008 Deutsche Bank reported a larger range of $4.6 to $8 million dollars for the Woodford shale in the Arkoma and Ardmore Basins.

Current Activities

Due to the lack of drilling activity in the Ardmore Basin, there is no data available. The Woodford shale in the Arkoma Basin had 166 vertical wells and 37 horizontal wells completed in 2007. According to PetroQuest, 4 wells are completed as of August 2010 and the company is expecting a 3-rig Woodford program by the end of the year. Devon Energy drilled 61 wells in 2009 and plans to have about 85 wells drilled in 2010.

USGS Comparison

In 2010, USGS conducted an assessment of the Woodford shale in the Arkoma Basin. They estimated that the total undiscovered resource is between 6,065 and 14,036 Bcf, with a mean of 10,068 Bcf. The shale gas resource in the Ardmore Basin has not been evaluated by USGS.

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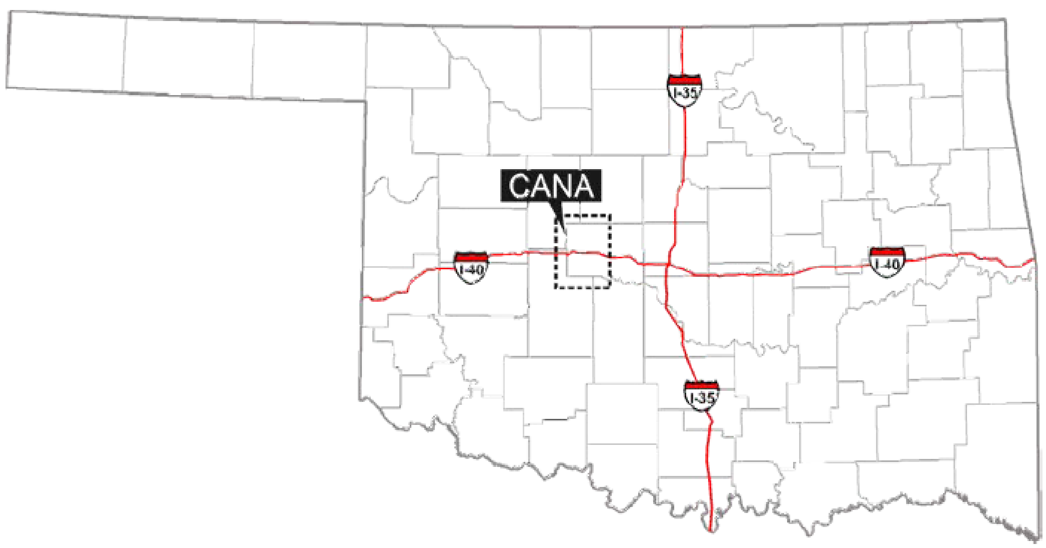
C. Cana Woodford Shale Gas Play

Play Description

Cana Woodford is an emerging gas play located within the Oklahoma Anadarko Basin, about 40 miles west of Oklahoma City (Figure 18). Companies have estimated that Cana Woodford contains a high liquid content of about 65% gas, 30% NGL and 5% oil.

Figure 18 Cana Woodford Shale Play



Resource Estimate

Based on companies' leased acreage for the shale, as provided in Table 33, the active area for Cana Woodford is approximately 688 square miles. Cana Woodford is said to be the world's deepest commercial horizontal shale play with depths that range from about 11,500 to 14,500 feet. The shale's EUR ranges from 4 to 12 Bcf with an average EUR of 5.2 Bcf per well. The TRR is estimated to be 5.7 Tcf with a well spacing of 4 wells per square miles (160 acres per well) as provided bellow in Table 33.

Table 33 Cana Woodford Average EUR and Area

	Active
Area (sq. miles)	688
EUR (Bcf/ well)	5.2
Well Spacing (wells/ sq. mile)	4
TRR (Tcf)	5.72

Other average properties estimated for Cana Woodford are provided in Table 34. These include the depth, thickness, porosity, and total organic content for the shale.

Table 34 Average General Properties for the Cana Woodford Shale Play

Depth (ft)	13,500
Thickness (ft)	200
Porosity (%)	7
Total Organic Content (% wt)	6

Active Companies

The active companies, along with their net acreage, are listed in Table 35.

Table 35 Cana Woodford Lease Holders

Company	Net Acreage
Devon Energy	230,000
Continental Resources	47,500
Cimarex Energy	97,000
Questar Resources	66,000

These companies have leased a total of 440,500 net acres (688 square miles).

Future Development

Since Cana Woodford is a new developing play, there is little information published for the future drilling activity for the companies who are currently holding leases within the shale.

Drilling Cost

According to companies that report activities within Cana Woodford, the average well cost ranges from $4 to $12 million dollars per horizontal well.

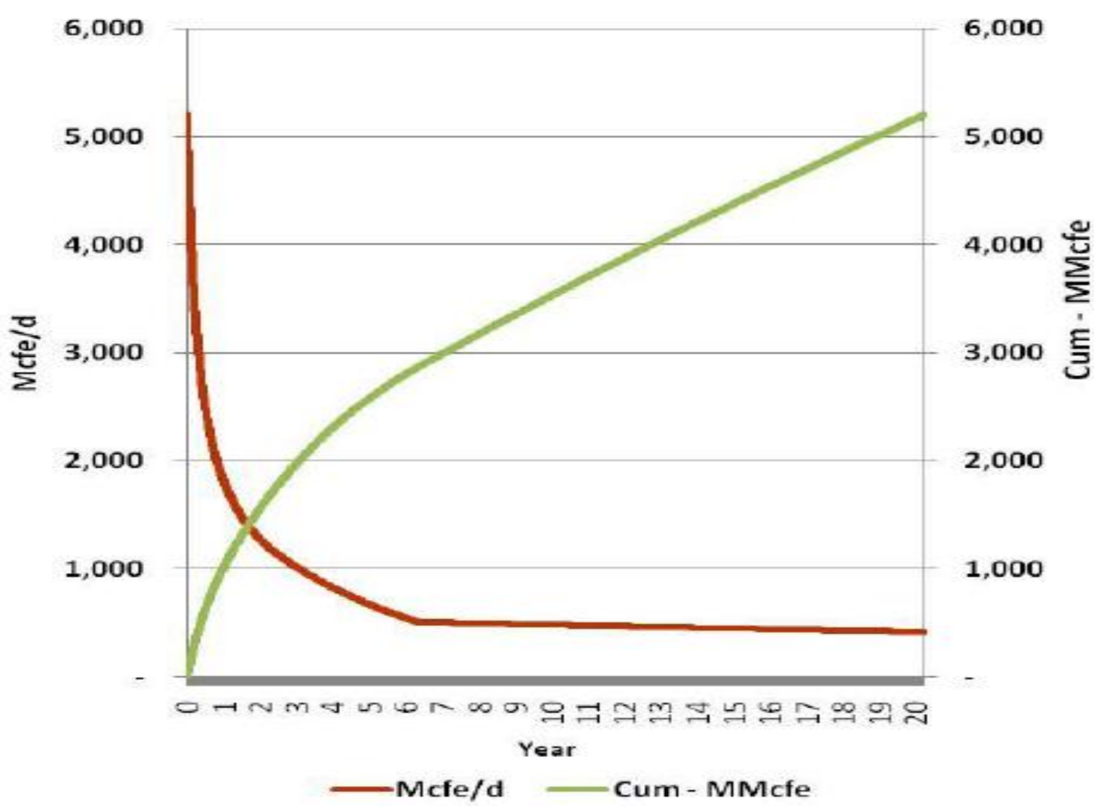
USGS Comparison

This play has not been evaluated by USGS.

Representative Type Curve

Figure 19 provides a Type Curve for Cana Woodford as reported by Cimarex Energy.

Figure 19 Cana Woodford Type Curve



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4. Continental Resources. *Pritchard Capital Bakken Mini- Conference.* May 2010.
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6. Devon Energy. *Devon Cana- Woodford Update: 11 Bcfe Type Curve.* June 2010.
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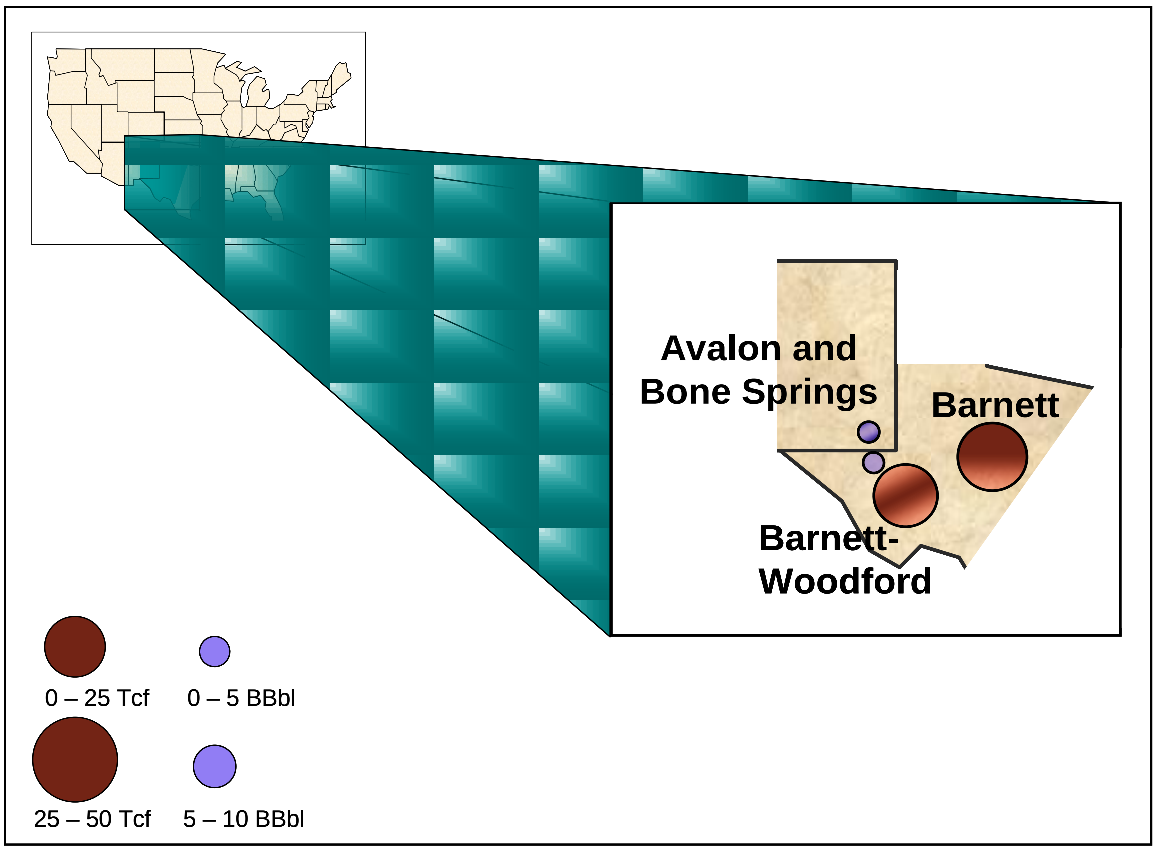
V. Southwest Regional Summary

The Southwest region includes shale gas and shale oil plays located in the Fort Worth and Permian Basins (Figure 20). Located within these basins is the Barnett, Barnett-Woodford and the Avalon and Bone Springs shale play with a total area of 10,462 square miles. The reviewed plays have an average per well EUR between 1.2 and 3.0 Bcf and 300 MBO. There is approximately 75.5 Tcf of technically recoverable gas and 1.58 Bbbl of technically recoverable oil.

Figure 20 Southwest Shale Gas and Shale Oil Resources



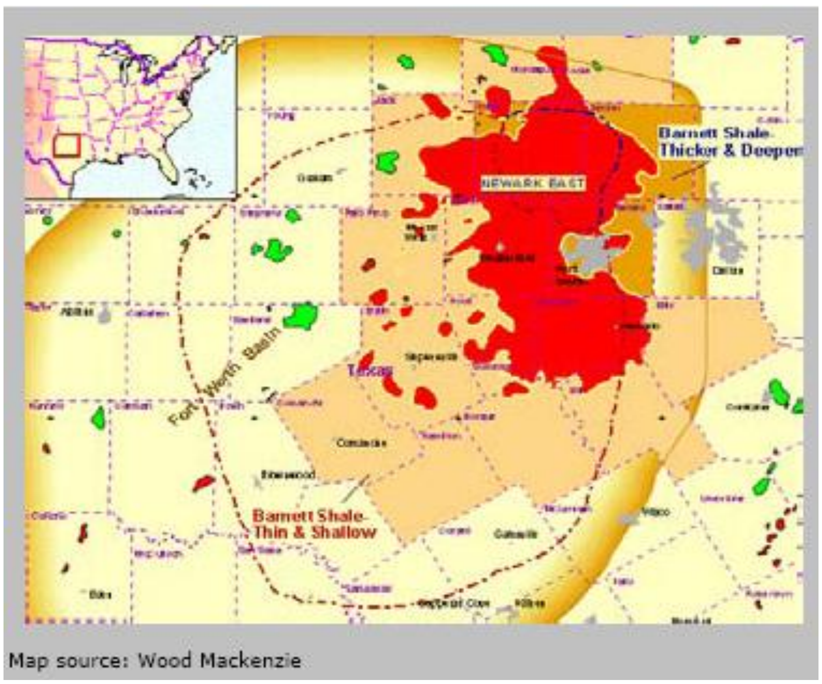
Southwest Region

A. Barnett Shale Gas Play

Play Description

The Barnett shale gas play is located within the Fort Worth and Permian Basins in Texas. The Barnett shale is divided into two sections: the "Core/Tier I" and the Undeveloped. The Core/Tier I section corresponds to the areas of the Barnett Shale that are currently under development. It is primarily located in the Parker, Wise, Johnson, and other neighboring counties. The undeveloped section corresponds with those areas of the Barnett that have not been developed by the companies. Because the Barnett extends across two petroleum basins that are in different regions of Texas, the active and undeveloped sections of the Barnett were further subdivided for modeling purposes. The location of the shale, as defined by Wood Mackenzie, is provided in Figure 21.

Figure 21 The Barnett Shale Play



Resource Estimate

The total area for the Barnett, as estimated by USGS is 6,458 square miles. This area is subdivided into two sections: the Greater Newark East Frac-Barrier Continuous Barnett Shale Gas (1,555 square miles) and the Extended Continuous Barnett Shale Gas (4,903 square miles). As the development of the Barnett extended beyond the Newark East field, the active section of the Barnett was also extended. The remaining area is considered to be undeveloped section of the Barnett. The TRR in these sections is shown in Table 36. The Barnett shale gas play, including the active and undeveloped areas, has an average EUR of 1.4 Bcf per well and approximately 43.37 Tcf of technically recoverable gas. An average EUR and well spacing for the active area are based on company data. These values were used to calculate the average well and TRR for the undeveloped section of the Barnett. These averages are summarized in Table 36.

Table 36 Average Barnett EUR and Area

	Active	Undeveloped
Area (sq. miles)	4,075	2,383
EUR (Bcf/ well)	1.6	1.2
Well Spacing (wells/ sq. mile)	5.5	8
TRR (Tcf)	23.81	19.56

Other average properties were estimated for the Barnett shale play. These include the depth, thickness, and porosity for the shale. The values, which are the same for the active and undeveloped sections, are provided in Table 37.

Table 37 Average General Properties for the Barnett Shale Play

Depth (ft)	7,500
Thickness (ft)	300
Porosity (%)	5

Active Companies

In 2008, there were 10 companies holding leases in the Barnett Shale Core and 10 companies in the South/Western section of the shale. These companies, along with their net acreage, are listed in Tables 38 and 39 respectively.

Table 38 Barnett Core/Tier 1 Lease Holders

Company	Net Acreage
Carrizo Oil & Gas	85,429
Chesapeake	260,000
Devon Energy	527,000
EnCana Corp	71,500
EOG Resources	96,000
Quicksilver	16,525
Parallel Petroleum	17,600
Range Resources	20,000
Williams Cos.	32,000
XTO Energy	125,000

Table 39 Barnett South/Western Counties Lease Holders

Company	Net Acreage
Chesapeake	19,400
Denbury	40,400
Devon Energy	199,900
EOG Resources	554,000
EnCana Corp.	71,500
Forest Oil	34,000
Petroleum Development	8,868
Quicksilver	247,000
Range Resources	57,000
XTO Energy	125,000

These Companies have leased a total of 2,608,122 net acres (4,075 square miles).

Well Costs

The well costs reported in 2008 and 2009 have been between $2 and $3 million dollars for a well in the Barnett Core. The costs in the Southern and Western counties have a larger range – between $1.6 and $3.7 million per well. The differences in costs are consistent with EOG Resources reported costs.

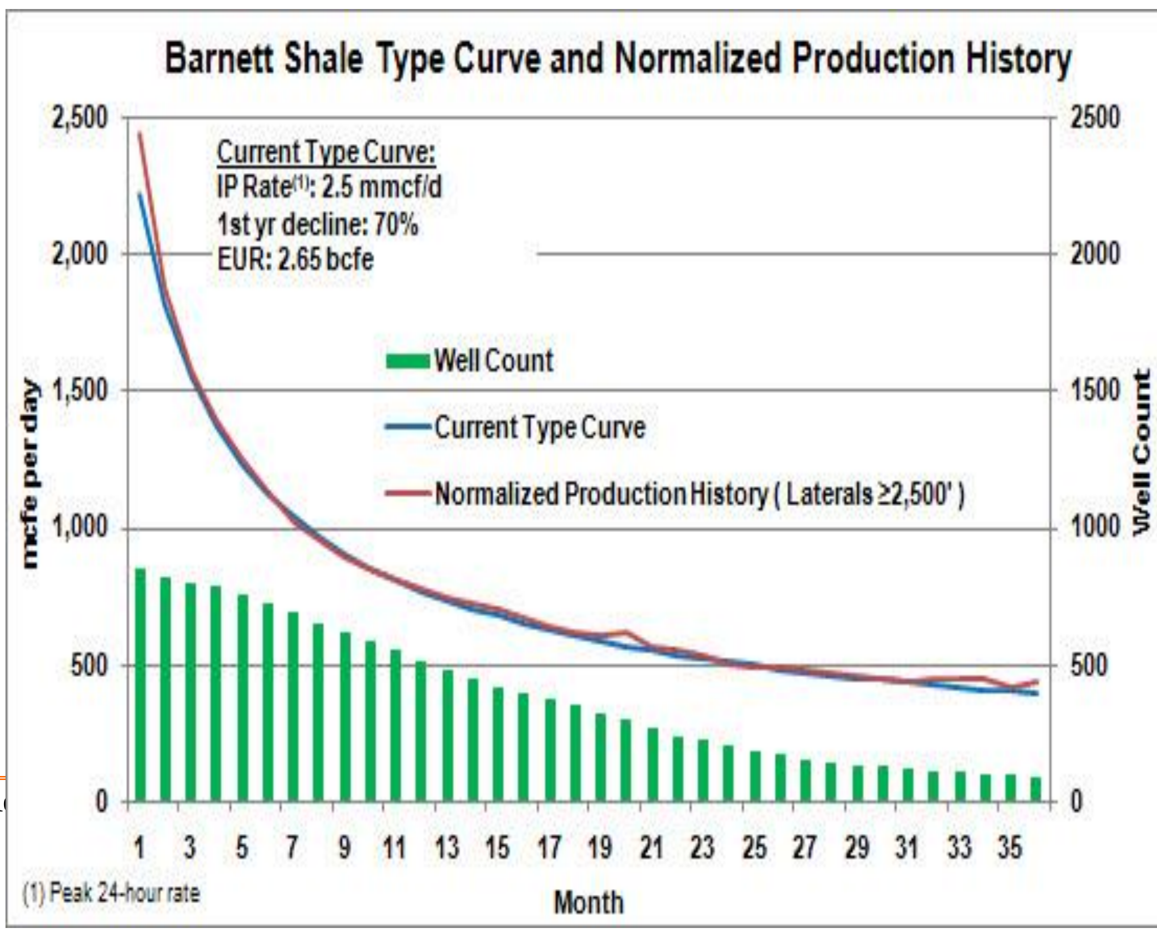
Current Activities

There is significant current drilling activity in the Barnett. There are at least 58 rigs currently active in the shale. Of these, 14 are operated by EOG Resources and 22 by Chesapeake.

Representative Type Curve

Figure 22 provides a representative type curve for a Barnett well.

Figure 22 Barnett Type Curve



USGS Comparison

In 2003, USGS completed an assessment of the undiscovered oil and gas resources within the Fort Worth Basin. As part of the study, they evaluated two assessment units within the Barnett-Paleozoic total petroleum system. The total undiscovered gas resource is between 21,716 Bcf and 31,521 Bcf, with a mean estimate of 26,229 Bcf.

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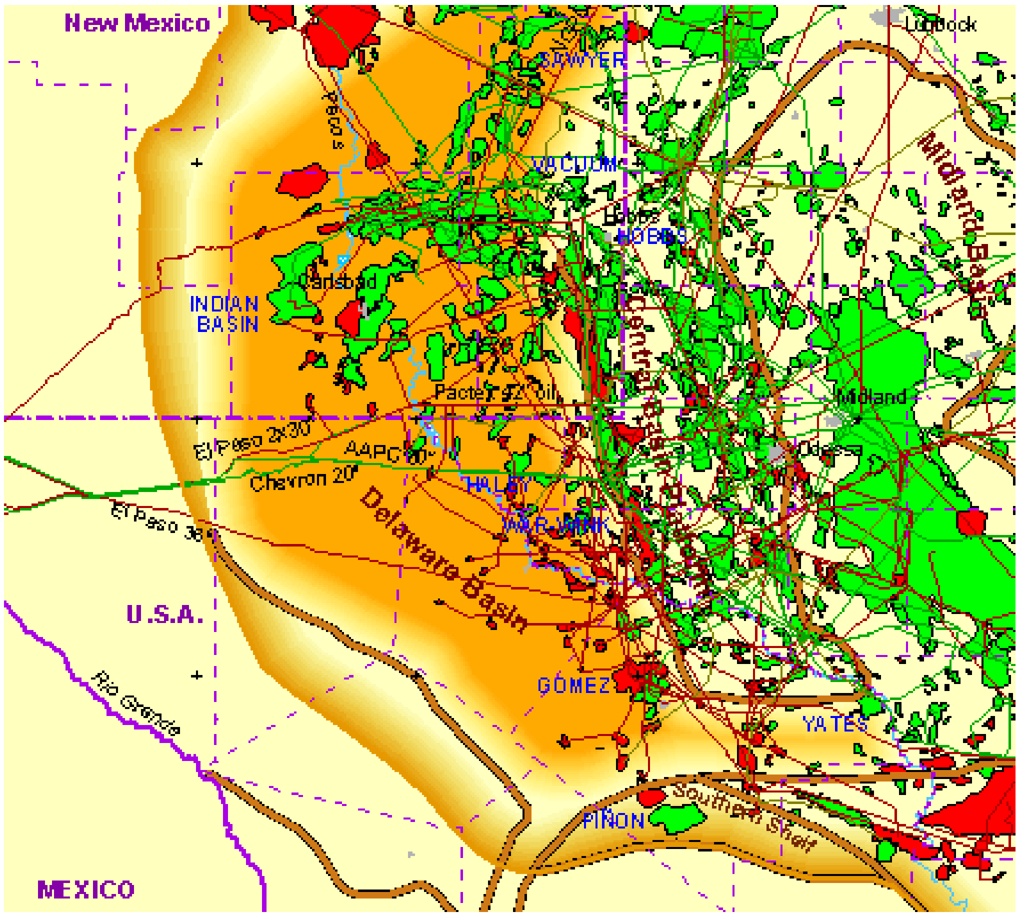
B. Barnett-Woodford Shale Gas Play

Play Description

The Barnett-Woodford shale gas play is located in the Permian Basin in West Texas. The location and area of the Barnett-Woodford shale is provided in Figure 23.

Figure 23 Barnett-Woodford Shale Play



Resource Estimate

The Barnett-Woodford shale play has an area of approximately 2,691 square miles combined from the net acreage in Table 38 and a well spacing of 160 acres per well (4 wells per square mile). The shale gas play has an average EUR of 3.0 Bcf per well and approximately 32.2 Tcf of technically recoverable gas. The shale ranges from 5,100 to 15,300 feet deep and 4 to 800 feet thick. These values are provided in Tables 40 and 41.

Table 40 Barnett-Woodford Average EUR and Area

	Active
Area (sq. miles)	2,691
EUR (Bcf/ well)	3.0
Well Spacing (wells/ sq. mile)	4
TRR (Tcf)	32.15

Other average properties were estimated for Barnett-Woodford. These include the depth, thickness and total organic content for the shale. Porosity data was not publicly available. The values are provided in Table 41.

Table 41 Average General Properties for the Barnett-Woodford Shale Play

	Active
Depth (ft)	10,200
Thickness (ft)	400
Porosity (%)	----
Total Organic Content (% wt)	5.5

Active Companies

In 2008, there were 8 companies holding leases in the Barnett-Woodford Shale. These companies, along with their net acreage, as reported by Deutsche Bank, are listed in Table 42.

Table 42 Barnett-Woodford Lease Holders

Company	Net Acreage
Abraxas	15,000
Carrizo Oil & Gas	70,000
Chesapeake	815,000
Continental Resources	67,000
EnCana Corporation	287,000
Quicksilver	375,000
Range Resources	20,000
TXCO Resources	73,500

Based upon these lease holdings, the total active area is calculated at 1,722,500 net acres (2,691 square miles).

Well Costs

According to Deutsche Bank in 2008, Barnett-Woodford has an average well cost of $6.5 million dollars.

USGS Comparison

This play has not been evaluated by USGS.

References

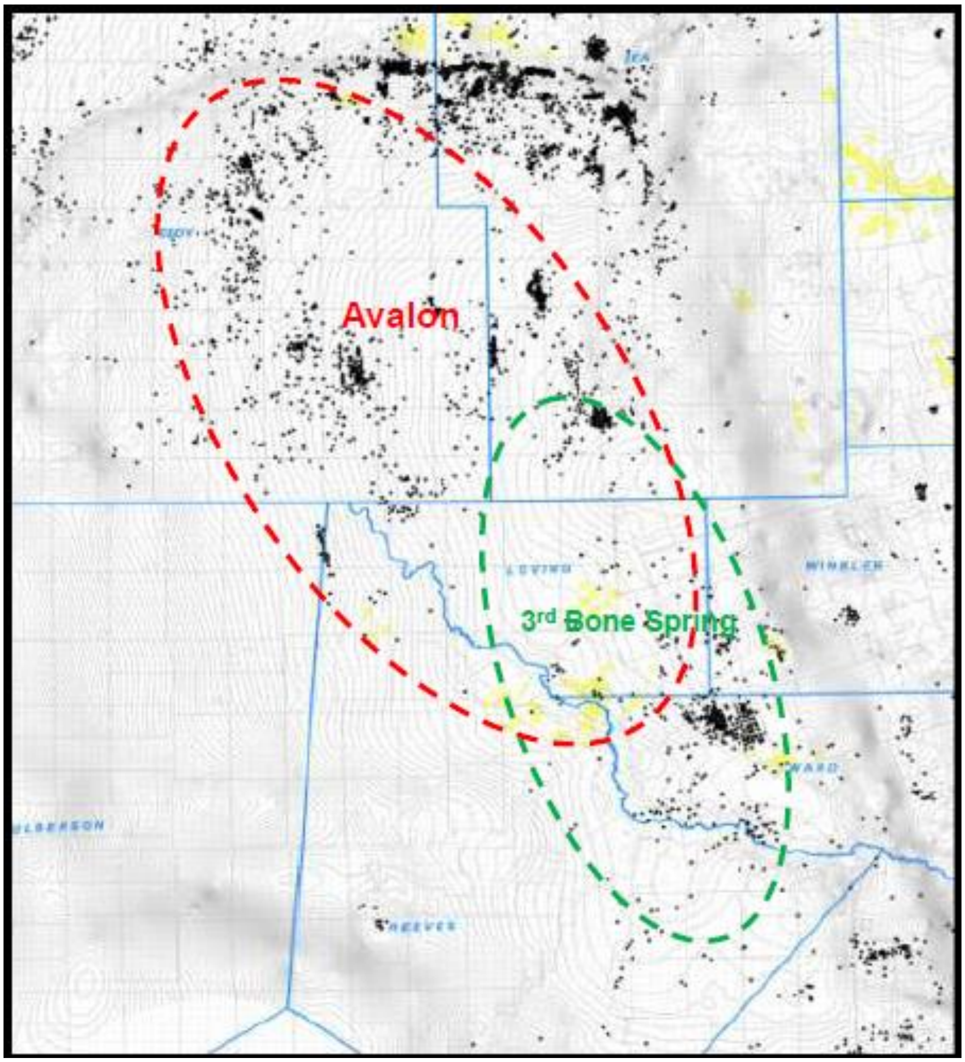
1. Deutsche Bank. *From Shale to Shining Shale.* July 2008.
2. The Discovery Group Inc. *Barnett Shale-Woodford Shale pay of the Delaware Basin- is it Another Giant Shale Gas Field in Texas?*
3. Marsh Operating Company. *Unconventional Gas Plays SPEE.* December 2007.

C. Avalon & Bone Springs Shale Oil Play

Play Description

The Avalon and Bone Springs shale oil play is located in the Permian Basin in Southeast New Mexico and West Texas. The Avalon play also includes the New Mexico Leonard Shale. Due to the lack of data published, Bone Spring and the Avalon shale are combined into a single unit. In Figure 24, SandRidge Energy shows the location and area of the shale play.

Figure 24 Avalon and Bone Springs Shale Play



Resource Estimate

The area for Avalon and Bone Springs was calculated using maps and other data reported by the companies who are currently leasing acres within Avalon and Bone Springs. The total active area is approximately 1,313 square miles. The shale oil play has an average EUR of 300 MBO per well and approximately 1.58 Bbbl of technically recoverable oil. The play has a reported depth from 6,000 to 13,000 feet and a thickness ranging from 900 to 1,700 feet. These values are provided in Table 43.

Table 43 Avalon and Bone Springs EUR and Area

	Active
Area (sq. miles)	1,313
EUR (MBO/ well)	300
Well Spacing (wells/ sq. mile)	4
TRR (BBO)	1.58

Other average properties were estimated for Avalon and Bone Springs. These include the depth and thickness. The values are provided in Table 44. Due to the lack of publicly reported data, the porosity and total organic content are undetermined.

Table 44 General Properties for the Avalon/Bone Springs Shale Play

	Active
Depth (ft)	8,750
Thickness (ft)	1,300
Porosity (%)	----
Total Organic Content (% wt)	----

Active Companies

In 2008, there were 6 companies holding leases in the Avalon and Bone Springs play. These companies, along with their net acreage, are listed in Table 45.

Table 45 Avalon and Bone Springs Lease Holders

Company	Net Acreage
Chesapeake	190,000
EOG Resources	120,000
Devon Energy	235,000
SandRidge Energy	25,000
Anadarko Petroleum	170,000
Concho	100,000

As of 2010, these companies have leased a combined total of 840,000 net acres (1,313 square miles).

Well Costs

According to Concho, the average well cost within the Bone Springs play range from $3 to $5 million dollars.

Current Activities

SandRidge Energy currently has 31 horizontal rigs drilling within the Bone Springs and Avalon shale play and according to Concho, as of August 2010, the industry has drilled 250 horizontal wells within Bone Springs play.

USGS Comparison

In 2007, USGS assessed the undiscovered oil and gas resources in the Permian Basin. This was the first time they broke out the continuous gas resources. However, the Avalon shale was not assessed at that time.

References

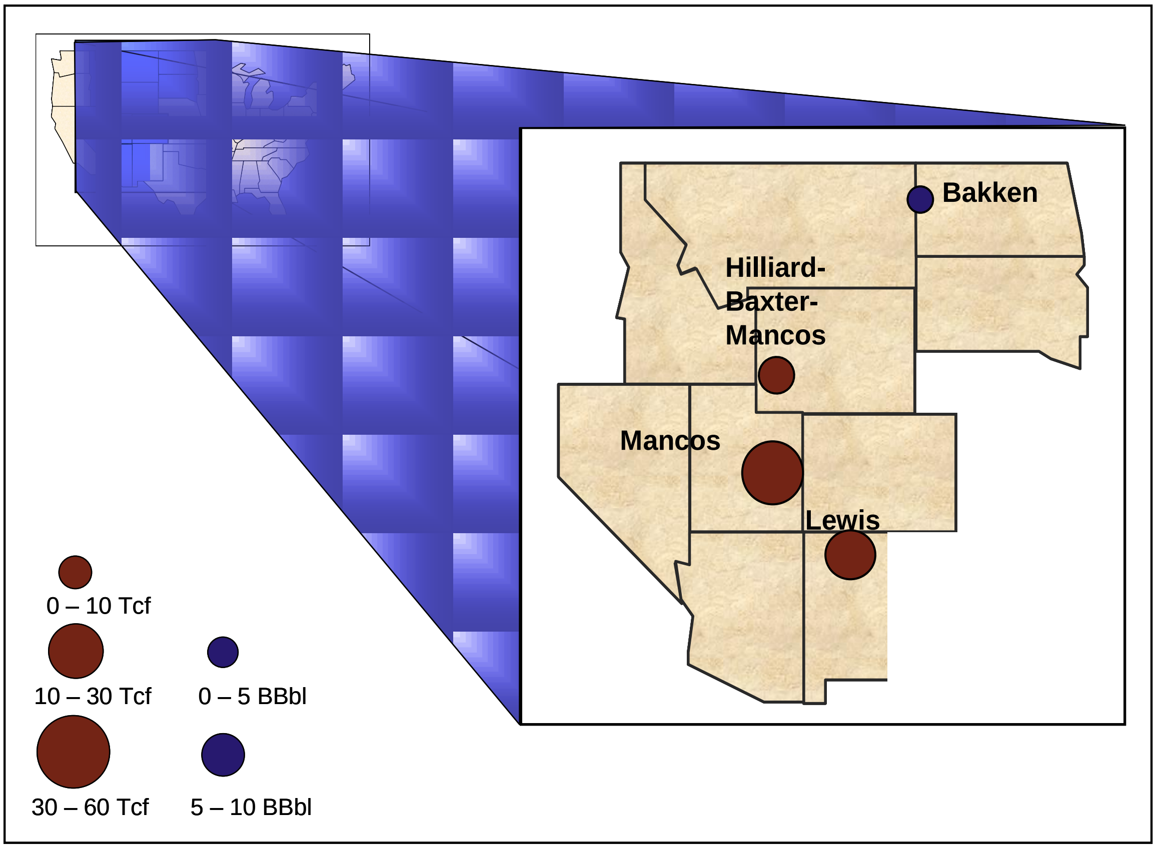
1. SandRidge Energy. *SandRidge- Investor Presentation*. August 2010.
2. Carrizo Oil & Gas. Presented at the Howard Weil 38th Annual Energy Conference. March 24, 2010.
3. USGS. *Assessment of Undiscovered Oil and Gas Resources of the Permian Basin Province of West Texas and Southeast New Mexico.* 2007.
4. USGS. *Bone Spring Formation.* September 2010.
5. Concho. *Investor Presentation*. August 2010.
6. http://www.oilshalegas.com/avalonshale.html
7. http://www.aapgbull.geoscienceworld.org/cgi/content/abstract/81/9/1423
8. Chesapeake Energy. *August 2010 Investor Presentation*. August 2010.
9. Cimarex Energy. *EnerCom Oil & Gas Conference.* August 2010.
10. Anadarko Petroleum Corporation. *Investor Conference.* March 2010.
11. PLS Inc. *Prospect Centre. Market Alert*. April 14, 2010.
12. PLS Inc. A&D Transactions. Market Alert. July 2010.

Avalon & Bone Springs

VI. Rocky Mountain Regional Summary

The Rocky Mountain region includes shale gas and shale oil plays in the Greater Green River, San Juan, Uinta, and Williston Basins. Located within these basins are the Hilliard-Baxter-Mancos, Lewis, Mancos and the Bakken shale plays with a combined area of 37,033 square miles (Figure 25). The reviewed plays have an average EUR between 0.18 and 1.3 Bcf and 55 MBO. There is approximately 43.0 Tcf of technically recoverable gas and 3.59 Bbbl of technically recoverable oil.

Figure 25 Rocky Mountains Shale Gas and Shale Oil Resources



Rocky Mountain Region

A. Hilliard-Baxter-Mancos Shale Gas Play

Play Description

The Hilliard-Baxter-Mancos shale gas play is located in the Greater Green River Basin in Wyoming and Colorado. According to Deutsche Bank, this is an environmentally sensitive region with high bottomhole pressures that complicates drilling completions. The location of the shale play is provided in Figure 26.

Figure 26 Hilliard-Baxter-Mancos Shale Play

Resource Estimate

According to USGS, the total active area for Hilliard-Baxter-Mancos is 16,416 square miles. The shale gas play has an average EUR of 0.18 Bcf per well and approximately 3.77 Tcf of technically recoverable gas. The depth for the shale ranges from 10,000 to 19,500 square miles and is 2,850 to 3,300 feet thick. These values are provided in Table 46.

Table 46 Hilliard-Baxter-Mancos Average EUR and Area

	Active
Area (sq. miles)	16,416
EUR (Bcf/ well)	0.18
Well Spacing (wells/ sq. mile)	8
TRR (Tcf)	3.77

Other average properties were estimated for the Hilliard-Baxter-Mancos shale play. These include the depth, thickness, porosity, and total organic content for the shale. These values are provided in Table 47.

Table 47 Average General Properties for the Hilliard-Baxter-Mancos Shale Play

	Active
Depth (ft)	14,750
Thickness (ft)	3,075
Porosity (%)	4.25
Total Organic Content (% wt)	1.75

Active Companies

In 2008, there were 5 companies holding leases in the Hilliard-Baxter-Mancos shale play. These companies, along with their net acreage, as reported by Deutsche Bank, are listed in Table 48.

Table 48 Hilliard-Baxter-Mancos Lease Holders

Company	Net Acreage
Anadarko Petroleum	unspecified
Devon Energy	157,000
Kodiak Oil & Gas	19,879
Questar	146,000
Ultra Petroleum	62,756

Based upon these lease holdings, the total active area is calculated at 385,634 net acres (603 square miles).

Well Costs

In 2008, Deutsche Bank reported an average well cost of $20 million dollars for the Hilliard-Baxter-Mancos shale play.

Current Activities

There is minimal information published for the current and future drilling activities of the companies who are currently holding leases within the shale.

USGS Comparison

In 2002, the USGS conducted an assessment of the Hilliard-Baxter-Mancos shale play. Their estimated area was 16,416 square miles. The USGS estimated that the total undiscovered resource for Hilliard-Baxter-Mancos continuous gas between 4.9 and 22.7 Tcf with a mean undiscovered resource of 11.8 Tcf.

References

4. Deutsche Bank. *From Shale to Shining Shale.* July 2008.
5. United States Geological Survey. *Assessment of the Undiscovered Natural Gas Resources of the Arkoma Basin Province and Geologically Related Areas.* 2010.
6. Rice University. *The Impacts of Cap-and-Trade, RPS, and Electric Vehicles on the North American Natural Gas Market.* June 2010.

B. Lewis Shale Gas Play

Play Description

The Lewis shale gas play is located in the San Juan Basin in Colorado and New Mexico. The location of the Lewis shale is provided in Figure 27.

Figure 27 Lewis Shale Play

Resource Estimate

According to USGS, the area for the Lewis shale play is approximately 7,506 square miles. The depth of the Lewis shale ranges from 1,640 to 8,202 feet deep and is 200 to 300 feet thick. The shale gas play has an average EUR of 1.3 Bcf per well and approximately 11.6 Tcf of technically recoverable gas. The well spacing for Lewis is estimated at 200 acres per well (3 wells per square mile). Theses average values are provided in Table 49.

Table 49 Lewis Average EUR and Area

	Active
Area (sq. miles)	7,506
EUR (Bcf/ well)	1.3
Well Spacing (wells/ sq. mile)	3
TRR (Tcf)	11.63

Other average properties were estimated for the Lewis shale play. These properties include depth, thickness and porosity as provided in Table 50. Due to a lack of current production and other issues within the play, the total organic content is undetermined.

Table 50 Average General Properties for the Lewis Shale Play

	Active
Depth (ft)	4,500
Thickness (ft)	250
Porosity (%)	3.5
Total Organic Content (% wt)	----

Active Companies

Information on the active companies and their leased acreage is not currently available.

Well Costs

Information on the well drilling and completion costs is not currently available.

USGS Comparison

In 2002, USGS conducted an assessment of the Lewis shale play. They estimated that the total undiscovered resource for the Lewis continuous gas is between 8,315 and 12,282 Bcf with a mean undiscovered resource of 10,177 Bcf.

References

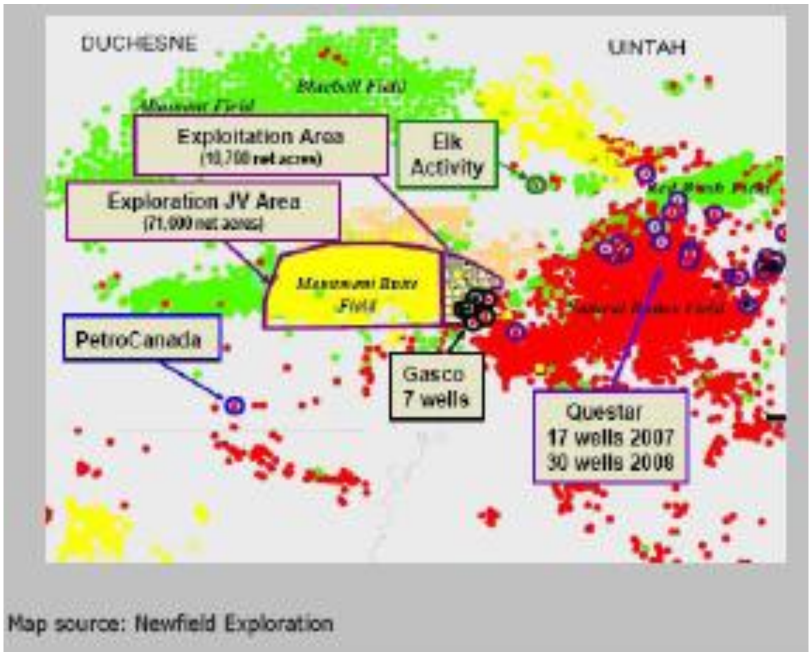
1. http://www.bjservices.com/website/index.nsf/webpages/Shale-Lewis-Page?OpenDocument
2. USGS. *Assessment of Undiscovered Oil and Gas of the San Juan Basin Province of New Mexico and Colorado.* 2002.
3. USGS. *San Juan Basin, Province 5022 (Province 22). 2003 Continuous Assessment Input Data*. 2003.
4. Jenkins, Creties, DeGolyer, MacNaughton, and Boyer, Charles II. *Coalbed- and Shale- Gas Reservoirs.* Journal of Petroleum Technology. February 2008.
5. John B Curtis. *Shale Gas: From Onerous Stepchild to Premier Resource*. 2008.

C. Mancos Shale Gas Play

Play Description

The Mancos shale gas play is located within the Uinta Basin in Colorado and Wyoming (Figure 28).

Figure 28 The Mancos Shale Play



Resource Estimate

In 2002, The Mancos shale was assessed by USGS as the Uinta Continuous Gas within the Mancos/Mowry total petroleum system. At that time, the median assessment area was estimated to be 4,217,000 acres (6,589 square miles). The EUR for the Mancos, apart from the Mesaverde, Wasatch, and other formations in the Uinta Basin, was reported as approximately 1.0 Bcf per well. The shale gas play is estimated to have 21.02 Tcf of technically recoverable gas. Typical well spacing for the Mancos shale was 40 to 80 acres. No company data was available in order to determine a minimum or maximum value for the EUR.

The Average calculated EUR for the Mancos shale is provided in Table 51.

Table 51 Mancos Average EUR and Area

	Active
Area (sq. miles)	6,589
EUR (Bcf/ well)	1.0
Well Spacing (wells/ sq. mile)	8
TRR (Tcf)	21.02

The shale is estimated to be between 13,000 and 17,500 feet deep and have an average thickness of 3,000 feet. The average values calculated for the Mancos shale are provided in Table 52.

Table 52 Average General Properties for the Mancos Shale Play

Depth (ft)	15,250
Thickness (ft)	3,000
Porosity (%)	3.5
Total Organic Content (% wt)	14

Active Companies

In 2008, there were 9 companies holding leases in the Mancos shale play. These companies, along with their net acreage, are listed in Table 53.

Table 53 Mancos Lease Holders

Company	Net Acreage
Anadarko Petroleum	60,000
Berry Petroleum	4,508
Cabot Oil & Gas	50,000
Chesapeake	440,000
Comstock	53,000
Cubic Energy	6,326
Devon Energy	200,000
El Paso	27,000
EnCana Corp.	325,000

These companies have leased a combined total of 1,165,834 net acres (1,822 square miles). These companies were just beginning to test and develop their acreage. No additional data could be found regarding their activities specifically in the Mancos shale.

USGS Comparison

In 2002, USGS completed an assessment of the Uinta Piceance Basin within Colorado and Utah. As part of the assessment, they examined the continuous gas within the Mancos/Mowry Total Petroleum System. USGS estimated that the area of the shale was 6,589 square miles and contained between 1.8 Tcf and 4.9 Tcf. The mean estimated resource is 3.1 Tcf of natural gas.

References

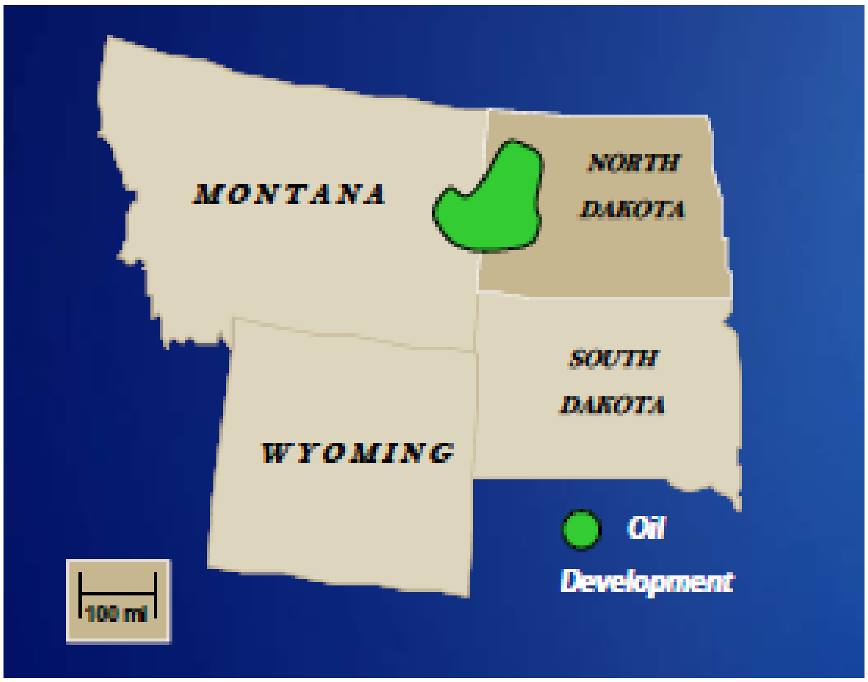
1. Deutsche Bank. *From Shale to Shining Shale. A Primer on North American Natural Gas Shale Plays.* July 2008.
2. USGS. *Assessment of Undiscovered Oil and Gas Resources of the Uinta-Piceance Province of Colorado and Utah.* 2002.

D. Bakken Shale Oil Play

Play Description

The Bakken shale oil play is located within the Williston Basin in Montana and North Dakota (Figure 29). While the shale extends into the Canadian provinces of Manitoba and Saskatchewan, only the United States portion is considered in this evaluation. This oil field could contain 3.65 billion barrels which would be the largest finding in U.S history.

Figure 29 Bakken Shale Play



Resource Estimate

Based on the leaseholders combined net acreage for Bakken, the area is approximately 6,522 square miles in the United States. The shale oil play has an average EUR of 550 MBO per well and approximately 3.59 Bbbl of technically recoverable oil. The Bakken shale ranges from 4,500 to 7,500 feet deep with a mean of 6,000 feet and an average thickness of 22 feet. According to Kodiak Oil and Gas Corporation and other companies, the well spacing ranges from 320 to 1,280 acres per well with a mean of 640 acres per well (1 well per square mile). These values are provided in Table 54.

Table 54 Bakken Average EUR and Area

	Active
Area (sq. miles)	6,522
EUR (MBO/ well)	550
Well Spacing (wells/ sq. mile)	1
TRR (BBO)	3.59

Other average properties estimated for Bakken are provided in Table 55. These include the depth, thickness, porosity, and initial oil saturation for the shale.

Table 55 Average General Properties for the Bakken Shale Play

Depth (ft)	6,000
Thickness (ft)	22
Porosity (%)	8
Initial Oil Saturation (%)	68

Active Companies

The active companies, along with their net acreage, are listed in Table 56.

Table 56 Bakken Lease Holders

Company	Net Acreage
Brigham Exploration	358,200
Concho Resources	11,193
Continental Resources	589,937
Encore Acquisition Company	70,000
GeoResources	49,000
Hess Corporation	500,000
Kodiak Oil and Gas Corporation	9,565
Marathon Oil Corporation	350,000
MDU Resources	56,000
Newfield Exploration	400,000
Oasis Petroleum	159,500
Parshall Field	18,188
Petroleum Development	16,200
Questar	89,000
Rosetta Resources	291,000
SM Energy	78,000
Southern Alberta Basin	224,000
Unit Corporation	12,750
Whiting Petroleum Corporation	442,092
XTO Energy	450,000

These companies have leased a total of 4,174,625 acres (6,522 sq. miles).

Current Activities

There are extensive activities within the Bakken shale play. Nearly all of the reported lease holders have given information about their 2010 development plans. Companies are running at least 45 rigs in 2010 and have indicated that number will increase to more than 54. Of these, 14 are operated by Continental Resources, 12 by EOG Resources, and 5 by Marathon Oil Corporation. In addition, many of the companies have significant capital programs devoted to the Bakken shale. Kodiak Oil and Gas Corporation has stated they plan to spend $60 millions dollars, Oasis will spend $144 million dollars in the West Williston Basin, and Whiting Petroleum Corporation will spend $284 million dollars for operations in the Sanish and Parshall sections of the Bakken shale play.

Well Costs

Well cost range form $5.5 to $8.5 million dollars. The vast majority of the companies which provide data have costs less than $7.2 million dollars. The lowest price, $5.5 million dollars, is also reported by Whiting Petroleum Corporation and Marathon Oil Corporation. In addition, Marathon Oil Corporation reports operating costs are less than $5 per barrel in the Bakken play.

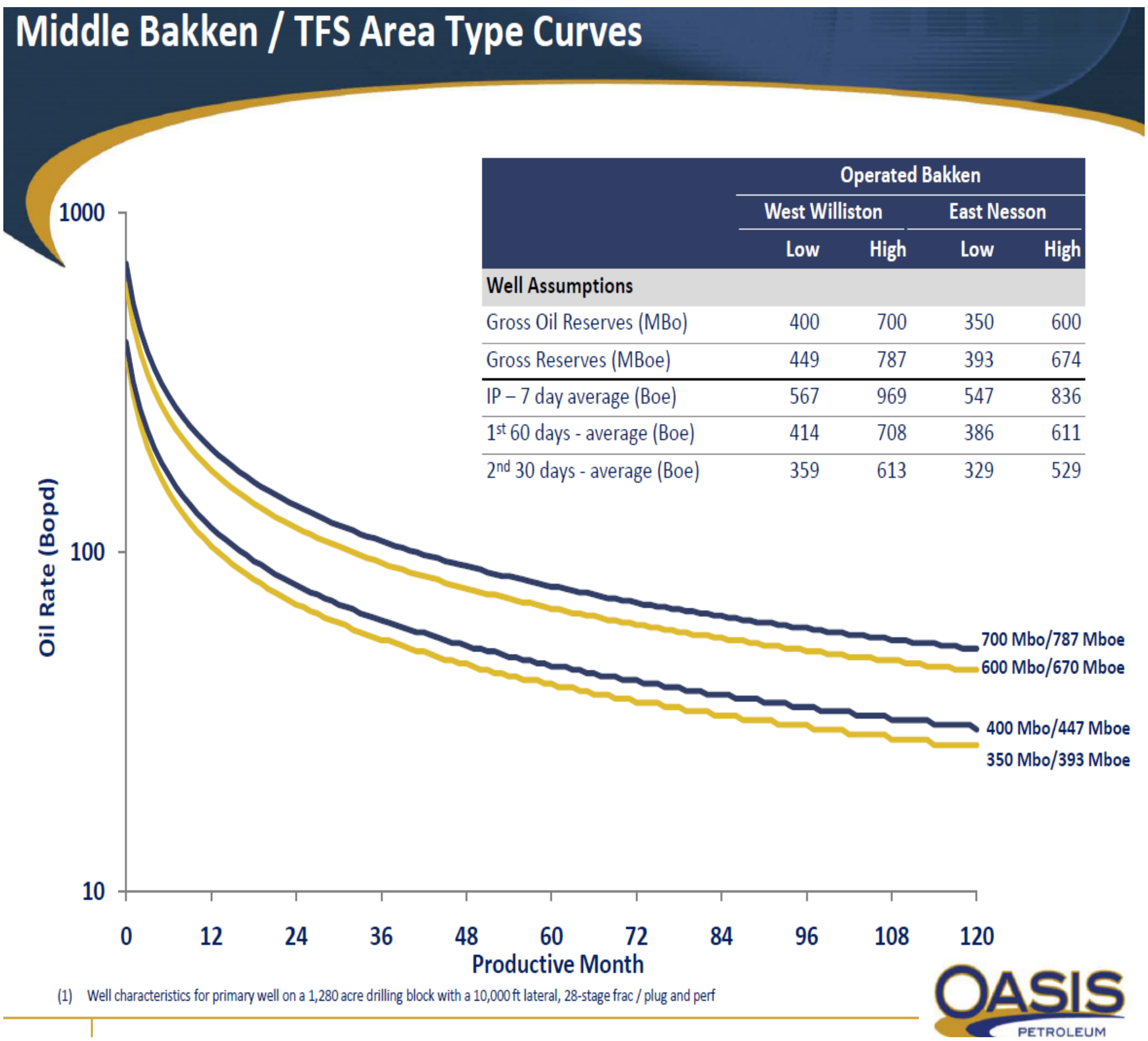
USGS Comparison

In 2008, USGS conducted an assessment of the Bakken shale. The total undiscovered resource is estimated between 3,063 and 4,319 MMOE, with a mean at 3,645 MMBO of total continuous resources.

Representative Type Curve

Figure 30 provides a representative type curve for Middle Bakken/ Three Forks area from Oasis Petroleum for Bakken in West Williston and East Nesson.

Figure 30 Bakken Shale Type Curve



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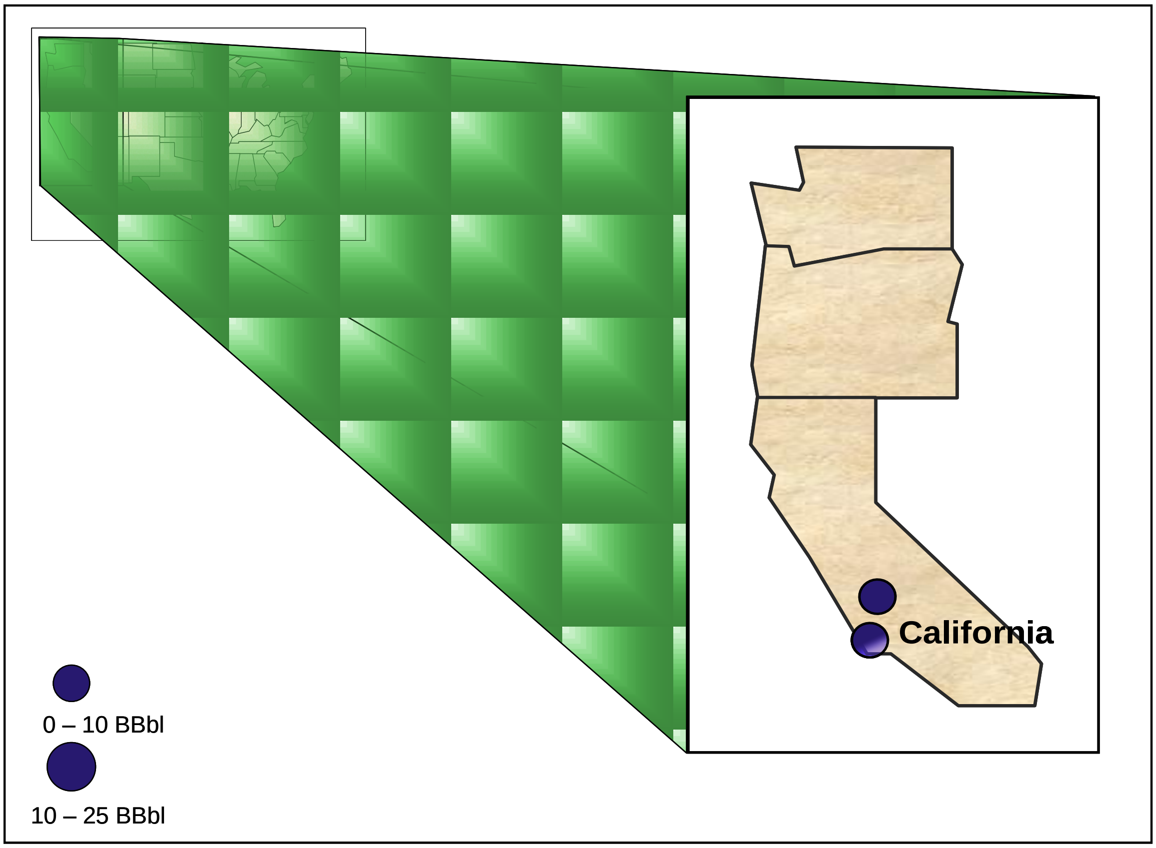
2. http://www.transformsw.com/resources/studies.html.
3. Rosetta Resources. *Rosetta Resources.* August 2010.
4. Kodiak Oil and Gas Corporation. *Corporate Presentation.* August 2010.
5. Denbury Resources. *Spring Analyst Meetings.* May 2010.
6. Continental Resources. *Bakken Shale: The Game-Changer from Hart's Developing Unconventional Oil Conference 2010.* May 2010.
7. Whiting Petroleum Corporation. *Current Corporate Information.* August 2010.
8. USGS. *Assessment of Undiscovered Oil and Gas Resources of the Williston Basin Province of North Dakota, Montana, and South Dakota*. 2008.
9. Oasis Petroleum. *Oasis Petroleum Company Presentation*. August 2010.
10. Concho. *Raymond James Boston Spring Investors Conference*. June 2010.
11. GeoResources. *GeoResources, Inc Corporate Profile*. August 2010.
12. SM Energy. *Macquarie Capital USA Small- & Mid- Cap Conference.* June 2010.
13. Deutsche Bank. *From Shale to Shining Shale.* July 2008.
14. QEP Resources. *Investor Presentation.* August 2010.
15. Newfield Exploration. *How the Pieces Fit Together UBS Global Oil & Gas Conference.* May 2010.
16. EOG Resources. *EOG Resources South Texas Eagle Ford.* 2010.
17. Marathon Oil Corporation. *UBS Global Oil & Gas Conference.* May 2010.
18. Hess Corporation. *Bernstein Strategic Decisions Conference*. June 2010.
19. Brigham Exploration Company. *EnerCom- The 2010 Oil & Gas Conference.* August 2010.
20. MDU Resources. *A Strong Infrastructure Utility Resources is the Heart of Energy our Economy Construction Materials.* March 2010.

VII. West Coast Regional Summary

The West Coast region includes shale oil plays in the San Joaquin and Los Angeles Basins (Figure 31). Located within these basins is the Monterey/Santos shale oil play with a total area estimated at 1,752 square miles. The reviewed play has an average EUR of 550 MBO per well and approximately 15.42 Bbbl of technically recoverable oil.

Figure 31 West Coast Shale Gas and Shale Oil Resources



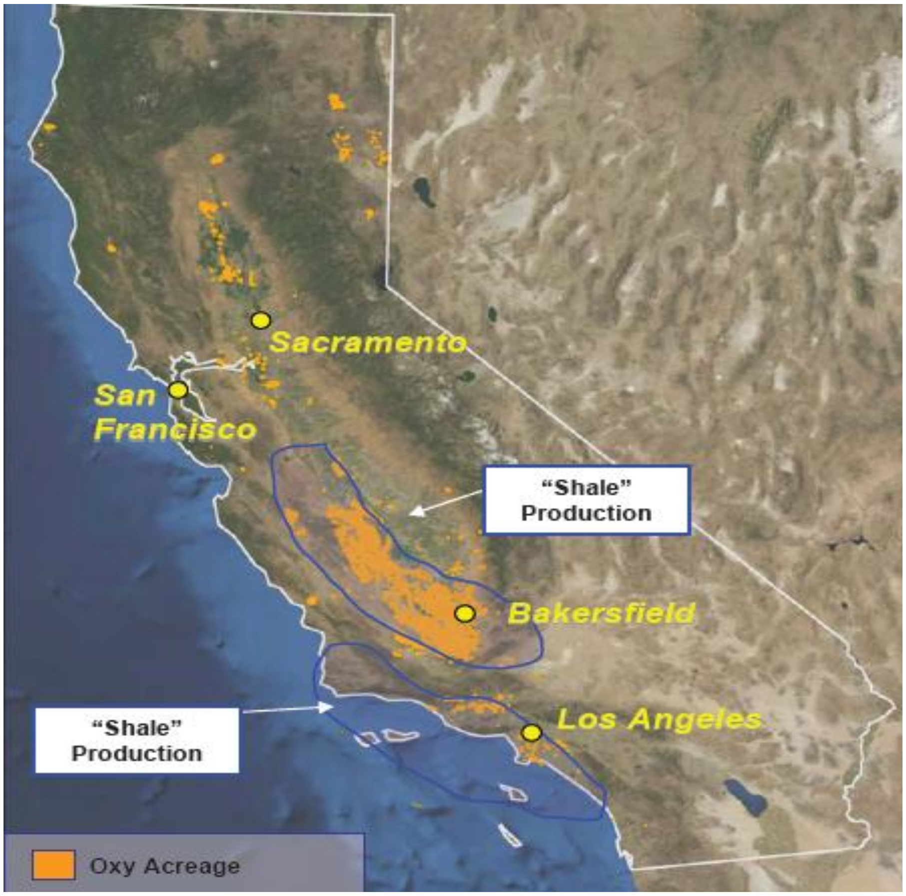
West Coast Region

A. Monterey/Santos Shale Oil Play

Play Description

The Monterey/Santos shale oil play includes the Lower Monterey and Santos shales and is located in the San Joaquin and Los Angeles Basins in California. The general location of the Monterey/Santos shale play is provided in Figure 32.

Figure 32 Monterey/Santos Shale Play



Resource Estimate

The active area for the Monterey/Santos shale play is approximately 1,752 square miles in the San Joaquin and Los Angeles Basin. The depth of the shale ranges from 8,000 to 14,000 feet deep and is between 1,000 and 3,000 feet thick. The shale oil play has an average EUR of 550 MBO per well and approximately 15.42 Bbbl of technically recoverable oil. These average values are provided in Table 57.

Table 57 Monterey/Santos Average EUR and Area

	Active
Area (sq. miles)	1,752
EUR (MBO/ well)	550
Well Spacing (wells/ sq. mile)	16
TRR (BBO)	15.42

Other average properties were estimated for the Monterey/Santos shale. These include the depth, thickness, porosity, and total organic content for the shale. The values are provided in Table 58.

Table 58 Average General Properties for the Monterey/Santos Shale Play

	Active
Depth (ft)	11,250
Thickness (ft)	1,875
Porosity (%)	11
Total Organic Content (% wt)	6.5

Active Companies

The companies, along with their net acreage who are currently holding leases within the Monterey/Santos shale play as of 2010, are listed in Table 59.

Table 59 Monterey/Santos Lease Holders

Company	Net Acreage
Berry Petroleum	6,500
National Fuel Gas Company (NFG)	14,000
Occidental Petroleum Company (Oxy)	873,000
Plains Exploration and Production	70,000
Venoco	158,000

Based upon these lease holdings, the total active area is calculated at 1,121,500 net acres (1,752 square miles).

Well Costs

Plains Exploration and Production Company reports an average gross well cost in 2010 of $1.2 million dollars per well. Oxy reports cost for vertical well ranging from $2 to $2.5 million and horizontal well costs ranging from $5 to 7 million. They also report finding and development costs between $8 and 18 dollars/BOE, depending upon the field.

Current Activities

Oxy Corporation has undertaken a 4-year development program and remains the largest leaseholder within the Monterey/Santos play. Seneca Resources/ NFG first went into production in February 2010 and have completed a 14 well development program. In 2010, Venoco completed their 1st horizontal well in the Monterey Basin and plan to increase their net acreage.

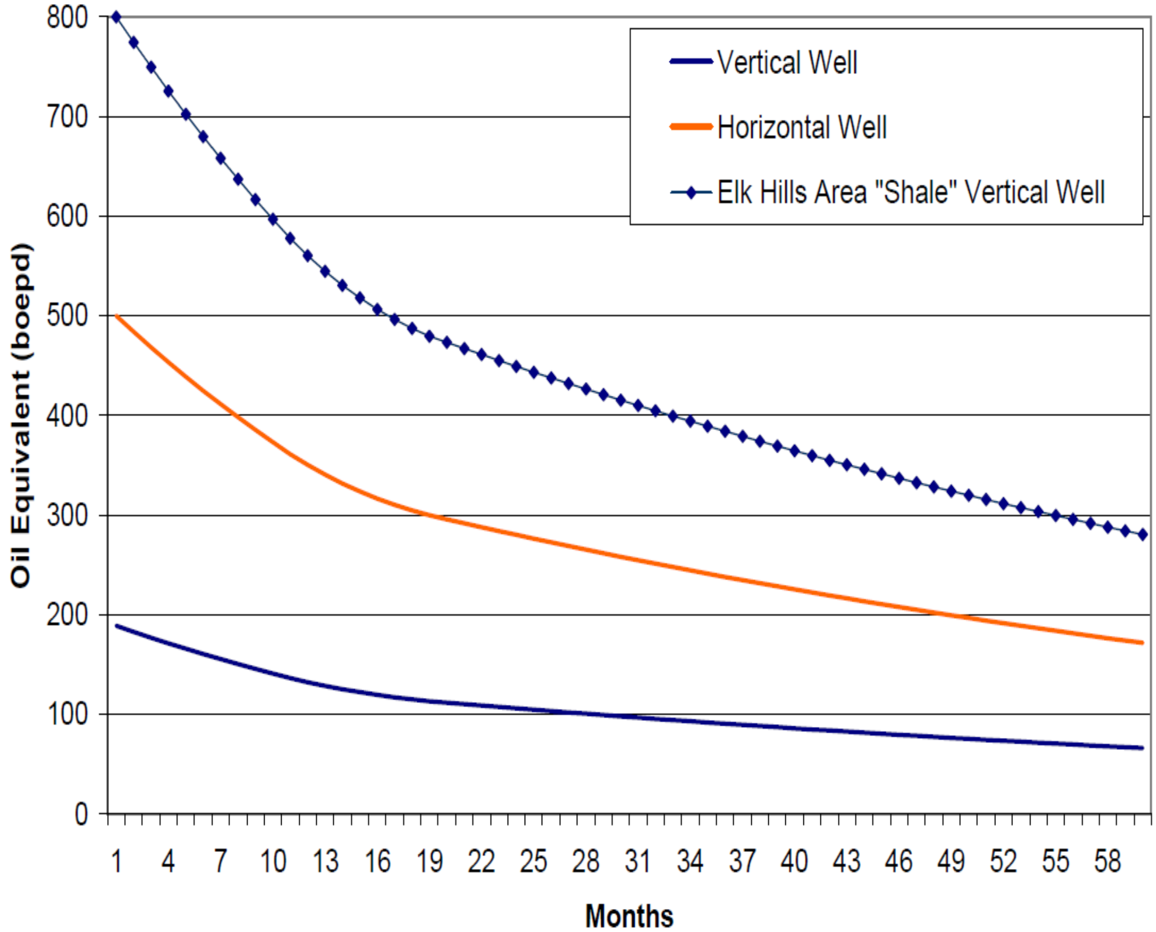
USGS Comparison

This play has not been evaluated by USGS.

Representative Type Curve

Figure 33 provides a representative type curve reported by Oxy Corporation for a vertical well, horizontal well, and for the Elk Hills Area "shale" vertical well within the Monterey/Santos shale play.

Figure 33 Monterey/Santos Type Curve



USGS Comparison

In 2003, the USGS conducted an assessment of the San Joaquin Basin. At that time, they did not assess the unconventional resources.

References

1. Todd Stevens with Oxy Corporation. *Monterey/Santos Unconventional*. May 2010.
2. Venoco Corporation. *September Update*. September 2010.
3. Plains Exploration and Production Company. *2Q 2010 Presentation.* August 2010.
4. Seneca Resources and National Fuel Gas Corporation. *EnerCom Oil and Gas Conference*. August 2010.
5. USGS. *Assessment of the Undiscovered Oil and Gas Resources of the San Joaquin Basin Province of Monterey/Santos.* 2003.
6. http://www.ogj.com/ogj/en-us/index/article-tools-template.articles.oil-gas-journal.exploration-development-2.2010.05.oxy-sees_major_growth.html
7. http://western-energy.com/pages/focus_areas.htm

VIII. Appendix A– OLOGSS Shale Gas Data File

The following table provides the key information contained in the shale gas data file used in the Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS). Within the OLOGSS model database, each shale play/subplay has 3 well productivity categories to capture the large variation in well EUR that exists within a play: 1) Best Area, which covers 30 percent of the total play/subplay wells, 2) Average Area, which covers 30 percent of the play/subplay wells, and 3) Below Average Area, which covers 40 percent of the play/subplay wells. The EURs presented in this report do not include natural gas plant liquids.

Play Name	Basin Area (sq. miles)	Well Spacing (wells/sq. mile)	Avg. Depth (ft)	EUR (Bcf/well)				Success Rate (fr)
				Top 10%	Next 20%	Next 30%	Next 40%	
Appalachia - Big Sandy Central Act	8675	8	3800	0.65	0.49	0.33	0.16	0.86
Best Area	2603	8	3800	0.86	0.65	0.43	0.22	0.86
Average Area	2603	8	3800	0.65	0.49	0.33	0.16	0.86
Below Average Area	3470	8	3800	0.49	0.37	0.24	0.12	0.86
Appalachia - Big Sandy Extension	1994	8	3800	0.65	0.49	0.33	0.16	0.86
Best Area	598	8	3800	0.86	0.65	0.43	0.22	0.86
Average Area	598	8	3800	0.65	0.49	0.33	0.16	0.86
Below Average Area	798	8	3800	0.49	0.37	0.24	0.12	0.86
Appalachia - Greater Siltstone Area	22914	11	2911	0.58	0.29	0.19	0.06	0.74
Best Area	6874	11	2911	0.77	0.39	0.26	0.08	0.74
Average Area	6874	11	2911	0.58	0.29	0.19	0.06	0.74
Below Average Area	9166	11	2911	0.44	0.22	0.14	0.04	0.74
Appalachia - Low Thermal Maturity	45844	7	3000	0.90	0.45	0.30	0.08	0.74
Best Area	13753	7	3000	1.20	0.60	0.40	0.10	0.74
Average Area	13753	7	3000	0.90	0.45	0.30	0.08	0.74
Below Average Area	18338	7	3000	0.68	0.34	0.23	0.06	0.74
Michigan Antrim	12000	7	1400	0.58	0.43	0.24	0.14	0.95
Best Area	3600	7	1400	0.77	0.57	0.32	0.19	0.95
Average Area	3600	7	1400	0.58	0.43	0.24	0.14	0.95
Below Average Area	4800	7	1400	0.44	0.32	0.18	0.11	0.95
Illinois New Albany Developing Area	1600	8	2750	3.30	1.67	1.10	0.26	0.5
Best Area	480	8	2750	4.39	2.22	1.46	0.35	0.5
Average Area	480	8	2750	3.30	1.67	1.10	0.26	0.5
Below Average Area	640	8	2750	2.48	1.25	0.83	0.20	0.5
Cincinnati Arch - Devonian Shales	6000	4	1800	0.36	0.18	0.12	0.03	0.5
Best Area	1800	4	1800	0.48	0.24	0.16	0.04	0.5
Average Area	1800	4	1800	0.36	0.18	0.12	0.03	0.5
Below Average Area	2400	4	1800	0.27	0.14	0.09	0.02	0.5
Williston - Shallow Niobraran	10000	2	1000	1.35	0.68	0.45	0.14	0.58
Best Area	3000	2	1000	1.80	0.90	0.60	0.18	0.58

Average Area	3000	2	1000	1.35	0.68	0.45	0.14	0.58
Below Average Area	4000	2	1000	1.01	0.51	0.34	0.10	0.58
Fort Worth Barnett - Core Area P	1426	5	7500	3.20	2.40	1.60	0.80	0.95
Best Area	428	5	7500	4.26	3.19	2.13	1.06	0.95
Average Area	428	5	7500	3.20	2.40	1.60	0.80	0.95
Below Average Area	570	5	7500	2.40	1.80	1.20	0.60	0.95
Fort Worth Barnett - Extension P	1906	8	7500	2.40	1.80	1.20	0.60	0.75
Best Area	572	8	7500	3.19	2.39	1.60	0.80	0.75
Average Area	572	8	7500	2.40	1.80	1.20	0.60	0.75
Below Average Area	762	8	7500	1.80	1.35	0.90	0.45	0.75
Fort Worth Barnett - Core Area F	2649	5	7500	3.20	2.40	1.60	0.80	0.95
Best Area	795	5	7500	4.26	3.19	2.13	1.06	0.95
Average Area	795	5	7500	3.20	2.40	1.60	0.80	0.95
Below Average Area	1060	5	7500	2.40	1.80	1.20	0.60	0.95
Fort Worth Barnett - Extension F	477	8	7500	2.40	1.80	1.20	0.60	0.75
Best Area	143	8	7500	3.19	2.39	1.60	0.80	0.75
Average Area	143	8	7500	2.40	1.80	1.20	0.60	0.75
Below Average Area	191	8	7500	1.80	1.35	0.90	0.45	0.75
Woodford-Barnett - Active	2691	4	10200	6.00	4.50	3.00	1.50	0.75
Best Area	807	4	10200	7.98	5.99	3.99	2.00	0.75
Average Area	807	4	10200	6.00	4.50	3.00	1.50	0.75
Below Average Area	1076	4	10200	4.50	3.38	2.25	1.13	0.75
Lewis Shale	7506	3	4500	3.25	2.44	1.30	0.82	0.95
Best Area	2252	3	4500	4.32	3.25	1.73	1.09	0.95
Average Area	2252	3	4500	3.25	2.44	1.30	0.82	0.95
Below Average Area	3002	3	4500	2.44	1.83	0.98	0.62	0.95
Fayetteville - Central	4000	8	4000	6.74	3.38	2.25	0.68	0.94
Best Area	1200	8	4000	8.96	4.50	2.99	0.90	0.94
Average Area	1200	8	4000	6.74	3.38	2.25	0.68	0.94
Below Average Area	1600	8	4000	5.06	2.54	1.69	0.51	0.94
Fayetteville - West	5000	8	4000	3.45	1.75	1.15	0.35	0.88
Best Area	1500	8	4000	4.59	2.33	1.53	0.46	0.88
Average Area	1500	8	4000	3.45	1.75	1.15	0.35	0.88
Below Average Area	2000	8	4000	2.59	1.31	0.86	0.26	0.88
Woodford - Western Arkoma	2900	4	9500	11.97	6.00	4.00	1.20	0.9
Best Area	870	4	9500	15.92	7.98	5.32	1.60	0.9
Average Area	870	4	9500	11.97	6.00	4.00	1.20	0.9
Below Average Area	1160	4	9500	8.98	4.50	3.00	0.90	0.9
Woodford - Central OK Fold Belt	1800	4	5000	2.99	1.50	1.00	0.30	0.86
Best Area	540	4	5000	3.98	2.00	1.33	0.40	0.86
Average Area	540	4	5000	2.99	1.50	1.00	0.30	0.86
Below Average Area	720	4	5000	2.24	1.13	0.75	0.23	0.86
Woodford - Cana	688	4	13500	15.56	7.80	5.20	1.50	0.86
Best Area	206	4	13500	20.69	10.37	6.92	2.00	0.86

Average Area	206	4	13500	15.56	7.80	5.20	1.50	0.86
Below Average Area	726	4	13500	11.67	5.85	3.90	1.13	0.86
Haynesville Shale-Developed	3574	8	12000	13.00	9.75	6.50	3.25	0.75
Best Area	1072	8	12000	17.29	12.97	8.65	4.32	0.75
Average Area	1072	8	12000	13.00	9.75	6.50	3.25	0.75
Below Average Area	1430	8	12000	9.75	7.31	4.88	2.44	0.75
Haynesville Shale-Undeveloped	5426	8	12000	3.00	2.25	1.50	0.75	0.75
Best Area	1628	8	12000	3.99	2.99	2.00	1.00	0.75
Average Area	1628	8	12000	3.00	2.25	1.50	0.75	0.75
Below Average Area	2170	8	12000	2.25	1.69	1.13	0.56	0.75
Appalachia - Marcellus Dev	10622	8	6750	7.00	5.25	3.50	1.75	0.7
Best Area	3187	8	6750	9.31	6.98	4.66	2.33	0.7
Average Area	3187	8	6750	7.00	5.25	3.50	1.75	0.7
Below Average Area	4249	8	6750	5.25	3.94	2.63	1.31	0.7
Appalachia - Marcellus Und- MD	920	8	6750	2.30	1.73	1.15	0.58	0.7
Best Area	276	8	6750	3.06	2.30	1.53	0.77	0.7
Average Area	276	8	6750	2.30	1.73	1.15	0.58	0.7
Below Average Area	368	8	6750	1.73	1.30	0.86	0.44	0.7
Appalachia - Marcellus Und- NY	16926	8	6750	2.30	1.73	1.15	0.58	0.7
Best Area	5078	8	6750	3.06	2.30	1.53	0.77	0.7
Average Area	5078	8	6750	2.30	1.73	1.15	0.58	0.7
Below Average Area	6770	8	6750	1.73	1.30	0.86	0.44	0.7
Appalachia - Marcellus Und- OH	15348	8	6750	2.30	1.73	1.15	0.58	0.7
Best Area	4604	8	6750	3.06	2.30	1.53	0.77	0.7
Average Area	4604	8	6750	2.30	1.73	1.15	0.58	0.7
Below Average Area	6139	8	6750	1.73	1.30	0.86	0.44	0.7
Appalachia - Marcellus Und- PA	29828	8	6750	2.30	1.73	1.15	0.58	0.7
Best Area	8948	8	6750	3.06	2.30	1.53	0.77	0.7
Average Area	8948	8	6750	2.30	1.73	1.15	0.58	0.7
Below Average Area	11931	8	6750	1.73	1.30	0.86	0.44	0.7
Appalachia - Marcellus Und- VA	3249	8	6750	2.30	1.73	1.15	0.58	0.7
Best Area	975	8	6750	3.06	2.30	1.53	0.77	0.7
Average Area	975	8	6750	2.30	1.73	1.15	0.58	0.7
Below Average Area	1300	8	6750	1.73	1.30	0.86	0.44	0.7
Appalachia - Marcellus Und- WV	18000	8	6750	2.30	1.73	1.15	0.58	0.7
Best Area	5400	8	6750	3.06	2.30	1.53	0.77	0.7
Average Area	5400	8	6750	2.30	1.73	1.15	0.58	0.7
Below Average Area	7200	8	6750	1.73	1.30	0.86	0.44	0.7
Eagleford Shale - DRY GAS	200	4	7000	11.00	8.25	5.50	2.75	0.892
Best Area	60	4	7000	14.63	10.97	7.32	3.66	0.892
Average Area	60	4	7000	11.00	8.25	5.50	2.75	0.892
Below Average Area	80	4	7000	8.25	6.19	4.13	2.06	0.892

Eagleford Shale - WET GAS	890	8	7000	9.00	6.75	4.50	2.25	0.892
Best Area	267	8	7000	11.97	8.98	5.99	2.99	0.892
Average Area	267	8	7000	9.00	6.75	4.50	2.25	0.892
Below Average Area	356	8	7000	6.75	5.06	3.38	1.69	0.892
Floyd/Neal-Conasauga	2429	2	8000	1.80	1.35	0.90	0.45	0.906
Best Area	729	2	8000	2.39	1.80	1.20	0.60	0.906
Average Area	792	2	8000	1.80	1.35	0.90	0.45	0.906
Below Average Area	972	2	8000	1.35	1.01	0.68	0.34	0.906
Uinta Mancos	6589	8	15250	2.00	1.50	1.00	0.50	0.95
Best Area	1977	8	15250	2.66	2.00	1.33	0.67	0.95
Average Area	1977	8	15250	2.00	1.50	1.00	0.50	0.95
Below Average Area	2636	8	15250	1.50	1.13	0.75	0.38	0.95
GGB Hilliard Baxter Mancos	16416	8	14750	0.36	0.27	0.18	0.09	0.8
Best Area	4925	8	14750	0.48	0.36	0.24	0.12	0.8
Average Area	4925	8	14750	0.36	0.27	0.18	0.09	0.8
Below Average Area	6566	8	14750	0.27	0.20	0.14	0.07	0.8